Public Version. Redactions in 2020 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs and Appendices

AEG
Applied Energy Group

2020 STATEWIDE LOAD IMPACT EVALUATION OF CALIFORNIA NON-RESIDENTIAL CRITICAL PEAK PRICING PROGRAMS

Ex-Post and Ex-Ante Load Impacts

CALMAC ID SDG0334

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Confidential information is removed and blacked out. [redacted]

Report prepared for:
PACIFIC GAS & ELECTRIC COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON

Energy Solutions. Delivered.

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ABSTRACT

This report documents the load impact evaluation of the non-residential Critical Peak Pricing (CPP) programs operated by the three California Investor-Owned Utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—for Program Year 2020 (PY2020). The CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when an event is called. As such, customers benefit financially from the longer periods of the lower rates for electricity consumed outside of the CPP periods. While the rates are similar at the three utilities, they are referred to by different names, e.g., Peak Day Pricing (PDP) at PG&E and CPP at SCE and SDG&E. The primary goals of this evaluation are to 1) estimate the ex-post load impacts for PY2020, and 2) estimate ex-ante load impacts for the programs for years 2021 through 2031.

The three California IOUs began defaulting their large commercial and industrial customer accounts onto CPP rates twelve years ago. Specifically, SDG&E began CPP default in 2008 followed by PG&E and SCE in 2010. Small and Medium Business (SMB) customers have been able to participate on a voluntary basis on CPP rates since 2014. However, all three utilities have begun, or completed their defaults of SMB customers within the past several years. In 2018, SDG&E completed their default of all SMB customers onto the CPP rates. In 2019 SCE began and completed the default of all their SMB customers with demands below 200 kW, along with large pumping and agricultural customers, onto the CPP rate. PG&E has suspended the PDP default to provide additional time for customers to adjust to the new TOU period implemented between 2019 and 2020. PG&E is set to resume defaulting customers onto PDP in March 2021. All newly enrolled customers receive bill protection for the first 12 months.

Each utility called a different number of events in PY2020. PG&E called a total of thirteen events, and SCE called twelve events and SDG&E called nine events. All events were called between May 1st and October 31st, and between 2 and 6 PM for PG&E and SDG&E and 4 and 9 PM for SCE. PG&E and SDG&E also called several events on weekends or Holidays. Some other program provisions including the notification period for events, the specific hours when CPP events can be called, and the number and duration of CPP events can vary by utility.

AEG estimated hourly ex-post load impacts for each program and event during PY2020, using regression analysis of subgroup-level hourly load, weather, and event data. The estimated load impacts are reported for each event by IOU and by customer size. Load impacts for the average event day are also reported by industry type and CAISO local capacity area (LCA), where relevant. In addition, AEG estimated ex-post impacts for CPP participants that received vs. did not receive notification. Estimated aggregate ex-post load impacts for an average event were 16.1 MW for PG&E and 12.5 MW for SCE and 5.5 MW for SDG&E.

AEG developed ex-ante load impact forecasts by combining enrollment forecasts provided by the IOUs, and per-customer load impacts generated from the analysis of current ex-post load impact estimates. The forecast numbers of nominated customer service accounts and aggregate ex-ante load impacts presented in the report reflect several program changes expected to take place beginning in 2021. AEG also estimated and incorporated the current and future impacts of COVID-19 in the ex-ante forecast. Estimated aggregate ex-ante load impacts for a typical event day in 2021 for a utility 1-in-2 weather scenario were 10.8 MW for PG&E, 14.0 MW for SCE, and were insignificant for SDG&E.

EXECUTIVE SUMMARY

This report documents the load impact evaluation of the non-residential Critical Peak Pricing (CPP) programs operated by the three California Investor-Owned Utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—for Program Year 2020 (PY2020). The CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when an event is called. As such, customers benefit financially from longer periods of lower rates for electricity consumed outside of the CPP periods. While the rates are similar at the three utilities, they are referred to by different names, e.g., Peak Day Pricing (PDP) at PG&E and CPP at SCE and SDG&E. Additionally, some program provisions including the notification period for events, the specific hours when CPP events can be called, and the number and duration of CPP events vary by utility, as illustrated in Table ES-1.

Table ES-1 Event Hours and Allowed Number of Events by Utility

Utility	Notification	Event hours	Events / year	Season
PG&E	Day ahead before 2 PM	2 to 6 PM	9 to 15	Year-round
SCE	~ 24-hour notice	4 to 9 PM	12	Year-round non-holiday weekdays
SDG&E	Day ahead before 3 PM	2 to 6 PM	Maximum of 18	Year-round

Research Objectives

The primary research objectives of the 2020 impact evaluation were to estimate both ex-post and ex-ante load impacts for the non-residential CPP programs. Specifically:

- This report presents PY2020 ex-post load impacts for the average participant and all participants in aggregate for each hour of each event day and the average event day for each IOU's CPP program. Ex-post results also include impacts at the program level and the following: size group, local capacity area (LCA), industry group, AutoDR and TA/TI, dually enrolled DR participants, and notified vs. non-notified participants.
- This report presents ex-ante load impacts for each year over a 12-year[1] time horizon, based on each IOU's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day both at the program and portfolio level. Portfolio level impacts exclude the load impacts of customers dually enrolled in another DR program. Ex-ante results also include impact estimates at the program level and the following: size group, LCA (as appropriate), and busbar (as appropriate) for both an average participant and all participants in aggregate for all program operating hours and the resource adequacy (RA) window (4 PM to 9 PM).

Program Descriptions

The three California IOUs began defaulting their large commercial and industrial customer accounts onto CPP rates thirteen years ago. Specifically, SDG&E began CPP default in 2008 followed by PG&E and SCE

[1] Eleven-year forecast for SCE.

in 2010.[2] Newly enrolled customers receive bill protection for the first 12 months. Most of the largest customers at PG&E and SDG&E currently have the option of reserving a level of generation capacity (a capacity reservation level, or CRL) to protect a portion of their load on CPP event days.[3] Small-to-Medium Business (SMB) customers have been able to participate on a voluntary basis on CPP rates since 2014. In 2018, SDG&E completed their default of all SMB customers onto the CPP rates. PG&E suspended the PDP default until the transition to new Time-of-Use (TOU) period is implemented in 2019-2020, so that the new customers are not subject to the PDP default right before or even simultaneously with the new TOU period. PG&E is set to resume defaulting customers onto PDP in March 2021. In March 2019, SCE defaulted onto the CPP rate SMB customers with demands below 200 kW, along with large pumping and agricultural customers. Moreover, in 2019, SCE changed the CPP event window from 2-6 PM to 4-9 PM and eliminated the CRL and CPP lite options.

PY2020 Event Days and Participant Counts

Each utility called a different number of events in PY2020. PG&E called a total of thirteen events, SCE called twelve events, and SDG&E called nine events. Events were called on weekdays and some weekends between May 1st and October 31st.

Table ES-2 presents the number of service accounts enrolled in CPP, or PDP, during a typical summer event by industry and utility. Table ES-3 presents the number of service accounts enrolled in CPP, or PDP, during an average summer event by size of maximum customer demand, including small (< 20 kW), medium (20 kW ≤ x < 200 kW), and large (> 200 kW).

Table ES-2 Enrolled Service Accounts, by Utility and Industry Group, Typical Event Day

Industry Type	PG&E	SCE	SDG&E
1. Agriculture, Mining & Construction	6,667	11,196	418
2. Manufacturing	4,555	10,953	1,149
3. Wholesale, Transport, Other Utilities	17,093	14,163	904
4. Retail Stores	9,583	33,257	1,770
5. Offices, Hotels, Finance, Services	34,648	110,076	6,592
6. Schools	2,256	3,020	736
7. Institutional/Government	20,431	32,949	1,810
8. Other/Unknown	6,397	28,477	297
Total	**101,629**	**244,091**	**13,675**

Table ES-3 Enrolled Service Accounts, by Utility and Industry Group, Typical Event Day

Industry Type	PG&E	SCE	SDG&E
Large (≥ 200 kW)	865	1,895	1,431
Medium (20 kW ≤ x < 200 kW)	13,914	29,581	12,244
Small (< 20 kW)	86,850	212,615	-
Total	**101,629**	**244,091**	**13,675**

[2] Most of the defaulted customers were previously served under tariffs with TOU energy and/or demand charges, such that they already had varying incentives to reduce load during peak periods on all summer weekdays.

[3] Effective March 2019, SCE no longer offers the CRL and CPP lite option.

Evaluation Methods

Ex-Post Analysis

AEG's approach to the ex-post analysis is described at a high level below and summarized in Figure ES-1.

- For subgroups where it was feasible, AEG developed a matched control group. For subgroups where it was not feasible, we employed a within subjects' design leveraging event-like days in 2020. Table ES-4 presents the methodology used to estimate impacts for each subgroup.
- Then, AEG estimated subgroup level models for each IOU, size, and industry. In some cases, we also estimated separate models for those who were notified of event and those who were not notified of events. All subgroup level models were ultimately selected using our optimization process.
- Based on lessons learned from the PY2019 LI analysis, AEG utilized customer-specific models for extremely large[4] customers. This approach minimized variation in the aggregate models and allowed for better impact estimates. Customer-specific regression model were developed using the optimization approach and methodology AEG employs in the Statewide Capacity Bidding Program Impact evaluation.[5]
- Finally, we estimated the ex-post impact for each customer so that they could be aggregated easily into the various reporting subgroups required for the analysis.

Figure ES-1 Ex-Post Analysis Approach

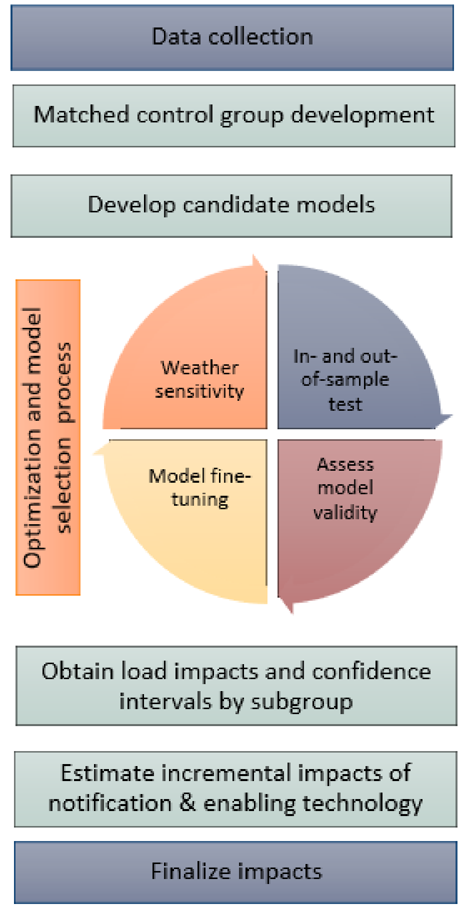

Table ES-4 presents the methodology AEG employed by utility and size group. We based the methodology on the total non-participant to participant ratio in each group. In general, a non-participant to participant ratio of at least 3 to 1 is needed to obtain a good match, therefore for groups with a ratio less than three, we employed a within subjects' design.[6] The within subjects' design leverages the participant's own load on event-like days to estimate the reference load.

[4] "Extremely large" customers were determined by participants' average daily loads. For PG&E, this was determined to be customers in the 90th percentile or top 10% of PG&E Large customers. For SCE, this was determined to be customers in the 95th percentile or top 5% of SCE Large customers.

[5] Applied Energy Group. (2021). 2020 Statewide Load Impact Evaluation of California Capacity Bidding Programs (CALMAC ID PGE0455). California Measurement Advisory Council.

[6] In addition to having small non-participant pools, the potential control group customers for the defaulted groups are made up of customers that opted out of the CPP rate. They are likely to be different than those that stayed on the rate and may introduce substantial self-selection bias into the analysis.

CPP is implemented differently within each IOU's territory. This, and the differences in methods, required the ex-post analysis to be conducted independently for each IOU. However, AEG used the same set of candidate models and optimization strategies across all three IOUs which maintained consistency in the results while allowing for customization of the models.

Table ES-4 Analysis Method by Subgroup

Utility	Size Group	Analysis Method
PG&E	Small	Within Subjects
	Medium	Within Subjects
	Large	***Matched control; Customer-specific for top 10%***
SCE	Small	Within Subjects
	Medium	Within Subjects
	Large	***Matched control; Customer-specific for top 5%***
SDG&E	Medium	Within Subjects
	Large	Within Subjects

Ex-Ante Analysis

AEG's PY2020 approach to the ex-ante analysis incorporated the current and future impacts of COVID-19 in the ex-ante forecast.

Comparisons of PY2020 results to previous program years showed that the effect of COVID-19 conditions are primarily found on the reference load or customers' overall usage. For non-residential customers, this was a decrease in average customer loads. The ex-post analysis showed changes and improvements to program impacts, however, this could also be attributed to several other factors that occurred in PY2020.

The ex-ante analysis described at a high level is as follows:

- Estimate annual weather-adjusted per-customer reference loads and load impacts using the coefficients from the ex-post models and the inputs from the weather scenarios.
- Estimate the effect of COVID-19 conditions for each IOU and size group using a simple regression analysis. Apply the effect to the reference load using IOU-specific factors to remove the COVID effect over time.
- Calculate the COVID-adjusted load impacts as a percent[7] of COVID-adjusted reference loads. This will allow the impacts to increase proportionally to the reference loads as usage returns to a no-COVID case.
- Multiply the annual per-customer impacts by the enrollment forecast to arrive at the aggregate load impact forecast.

Results

The results from the PY2020 CPP, or PDP, evaluation are summarized at the state-level as well as the utility-level in the subsections that follow.

State-Level Ex-Post Impacts

Table ES-5 presents the total enrollments, reference loads, load impacts, and event temperatures for the three IOU programs. In addition, the table presents the statewide total impacts for a typical event day. It is important to note that the typical event days vary by IOU based on their own weather patterns and

[7] Percentage is determined using the weather-adjusted estimates, i.e., weather-adjusted load impacts divided by weather-adjusted reference loads.

event calling strategies, therefore this PY2020 statewide total likely overestimates what might be achievable across the state should a statewide event be needed. PG&E has the largest contribution to the overall state level total of 16.1 MW, contributing 47% of the load reduction while SCE contributes 37% and SDG&E contributes 16%.

Table ES-5 Total State Level Ex-Post Impacts by Utility: Typical Event Day

Utility	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
PG&E - PDP	101,629	807	16.1	2.0%	94.8
SCE - CPP	244,091	1,283	12.5	1.0%	84.6
SDG&E - CPP	13,675	624	5.5	0.9%	89.2
Statewide	**359,395**	**2,714**	**34.1**	**1.3%**	**87.7**

In Table ES-6 below, we also present the impacts by customer size. The large participants contribute 63% of the total impacts across the state. As noted above, the small and medium customers also showed measurable impacts this year, although they were quite small at the per-customer level, contributing 13% and 24%, respectively.

Table ES-6 Total State Level Ex-Post Impacts by Customer Size: Typical Event Day

Size	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Large (≥ 200 kW)	4,191	848	21.4	2.5%	89.9
Medium (20 kW ≤ x < 200 kW)	55,739	1,378	8.2	0.6%	88.3
Small (< 20 kW) [8]	299,465	488	4.6	0.9%	84.5
Statewide	**359,395**	**2,714**	**34.1**	**1.3%**	**85.1**

Statewide, the total MW impact increased from 19.2 MW in PY2019 to 34.1 MW in PY2020 an increase of nearly 78%. Impacts for both PG&E and SCE improved in PY2020. SDG&E also called events, contributing 5.5 MW (39% of the increase) to the overall statewide impact. Improvements in impacts for PG&E and SCE are concentrated primarily in the small and medium groups, although impacts did increase relative to PY2019 across the board. Key observations related to these improvements include the following.

- Across all three IOUs, the weather was more extreme in PY2020. While the overall average temperatures were similar to PY2019, a significant heatwave hit the state in late August and early September bringing record temperatures. For weather sensitive customers the increased heat also resulted in increased impacts. Additionally, having more extreme days in our underlying data allowed for more accurate modeling of weather relationships which may also have contributed to the increase impacts.
    - PG&E's average temperature on a typical event day in PY2020 was 95° F vs. 94° F in PY2019. Additionally, the maximum average event temperature was 103° F vs 96° F in PY2020 vs. PY2019.

[8] SDG&E's Small CPP participants are included in the SCTD evaluation and are therefore excluded from the total.

  - SCE's average temperature on a typical event day in PY2020 was 85° F vs. 88° F in PY2019. Additionally, the maximum average event temperature was 89 vs 90° F in PY2020 vs. PY2019. SCE's temperatures were lower due to a high concentration of participants along the coast where temperatures tend to remain cooler, especially in the small and medium groups.
  - SDG&E's average event temperature on a typical event day in PY2020 was 89° F and the maximum average temperature was 99° F.
- COVID-19 conditions may also have affected how customers responded to CPP events. Given the depressed economic conditions across the country, it is possible that participants had additional incentive to save energy (and money) over the summer of 2020. Also, reduced capacities at many retail and restaurant locations may have facilitated additional response.
- PG&E's PDP population experienced a significant migration from the large group to the medium group and from medium to small. We suspect this influx of larger customers in to the medium and small groups are in large part responsible for the increase in impacts.[9]
- SCE's large default population in the small and medium groups also entered their second year of participation on CPP. After twelve months, these participants lost their bill protection guarantee and were exposed to the full monetary impacts of the rate. This may have encouraged customers to increase their response to the rate.
- As noted above SDG&E called events in PY2020 vs. no events in PY2019. SDG&E customers contributed 5.5 MW or 40% of the increase to the total.

State-Level Ex-Ante Impacts

Next, we present the state level ex-ante impacts for a Utility 1-in-2 weather year for program years 2021 and 2031 in Table ES-7. Keep in mind that the RA window for the 2021-2031 ex-ante forecast is 4-9 PM. SCE's event window aligns with the RA window, and PG&E's event window is shifting to 5-8 PM[10] effective March 2021. However, SDG&E's event windows will remain 2-6 PM, which means that SDG&E's CPP program is only available during the first two hours of the RA window while all other hours are non-event hours. This can result in significantly lower (and sometimes even negative) impacts within the RA window.

In program year 2021, the utilities forecast approximately 24.8 MW of load reduction to be available during the RA window. In 2021, SCE expects to contribute approximately 56% of the overall impacts, PG&E contributing 47%, and SDG&E contributing -4% – increasing loads on average during the RA window due to snapback after the event.

By 2031, the IOUs forecast a total of 24.3 MW of demand response on a typical event day. SCE predicts an increase in enrollments and impacts to 17.1 MW, but PG&E predicts a steep decline in enrollments and impacts to 7.6 MW.[11] SDG&E also predicts an overall decrease in enrollments and an associated reduction in load increases during the RA window to -0.4 MW.

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[9] It is unclear whether the migration between customer size groups is a result of COVID conditions or, a result of some reclassification efforts on PG&E's side. Therefore, we maintain the existing size group distribution of participants throughout the ex-ante forecast.

[10] Pending CPUC decision for R.20-11-003, the PDP event window is expected to be modified to 4 to 9 PM at a later point.

[11] PG&E's enrollment forecast incorporates the attrition trend from PY2019 to PY2020 and extends this trend into all future years. Without backfill from additional defaults after March of 2021, attrition continues to erode the program participation as shown.

Table ES-7 Total State Level Ex-Ante Impacts by Utility: Utility 1-in-2, Typical Event Day

Utility	PY 2021 Enrollment	PY 2021 Load Impact (MW)	PY 2031 Enrollment	PY 2031 Load Impact (MW)
PG&E- PDP	126,582	11.8	37,295	7.6
SCE - CPP	255,557	14.0	296,059	17.1
SDG&E - CPP	8,320	-0.9	3,063	-0.4
Statewide	**390,459**	**24.8**	**336,417**	**24.3**

In Table ES-8, we also present the ex-ante impacts for 2021 and 2031 by customer size. In the ex-ante scenario, the large customers still contribute most of the impacts in 2031, with changes in impacts due to changing enrollments across the three size groups and utilities.

Table ES-8 Total State Level Ex-Ante Impacts by Customer Size: Utility 1-in-2, Typical Event Day

Size	PY 2021 Enrollment	PY 2021 Load Impact (MW)	PY 2031 Enrollment	PY 2031 Load Impact (MW)
Large (≥ 200 kW)	4,749	18.6	3,117	16.8
Medium (20 kW ≤ x < 200 kW)	55,495	3.9	41,591	5.5
Small (< 20 kW) [12]	330,216	2.3	291,709	2.0
Statewide	**390,460**	**24.8**	**336,417**	**24.3**

Event Communication

It is also important to keep in mind that not all the customers that were enrolled in CPP, or PDP, received communication regarding events. As customers were defaulted onto the rates, each utility established mechanisms to reach out to customers to obtain contact information that could be used to provide day ahead event notification, however, in many cases customers did not respond to the utility outreach and therefore were unaware of the events throughout the summer. Table ES-9 shows the percentage of participants that were notified by utility and size group on a typical event day.

Interestingly, we saw very little evidence among the participating customers within the IOU programs that indicates notifications are having a significant effect on impacts. In fact, in many cases we see the groups of customers that have not elected email or text notification with larger per-customer impacts than those that have elected to receive notification. While this is counterintuitive, we also know that the IOUs communicate about events to customers using multiple channels including on mobile DR apps, utility websites, and social media.

Table ES-9 Percent of Service Accounts Notified, by Utility and Size Group, Typical Event Day

Size Group	PG&E % Notified	SCE % Notified	SDG&E % Notified
Large (≥ 200 kW)	87%	81%	63%
Medium (20 kW ≤ x < 200 kW)	87%	86%	48%
Small (< 20 kW)	84%	86%	-
Total	**84%**	**86%**	**50%**

[12] SDG&E's Small CPP participants are included in the SCTD evaluation and are therefore excluded from the total.

Key Findings by Utility

The key results for each utility on a typical event day are summarized in Table ES-10 (PG&E), Table ES-11 (SCE), and Table ES-12 (SDG&E).

Table ES-10 Key Results for PG&E's Peak Day Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
PG&E	Large	865	220	7.7	3.5%	96.4
	Medium	13,914	383	4.6	1.2%	95.9
	Small	86,850	204	3.8	1.8%	92.5
ALL PG&E		**101,629**	**807**	**16.1**	**2.0%**	**94.8**

The Large customers participating in PG&E's PDP program in 2020 demonstrate large and consistent load impact reduction, similar to past years. In addition, the medium and small customer groups show small but consistent load reductions which are an improvement over previous years likely attributable to extreme weather and possibly increased sensitivity to price resulting from COVID-19 conditions.

Table ES-11 Key Results for SCE's Critical Peak Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
SCE	Large	1,895	330	8.3	2.5%	87.2
	Medium	29,581	669	3.4	0.5%	84.4
	Small	212,615	284	0.8	0.3%	81.2
ALL SCE		**244,091**	**1,283**	**12.5**	**1.0%**	**84.6**

The large customer group in SCE's CPP Program also demonstrates large and consistent load impact reduction. In addition, the small and medium customers defaulted by SCE show improvements in their response this year, although the per-customer impacts are still very small.

Table ES-12 Key Results for SDG&E's Critical Peak Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Event Temp
SDG&E	Large	1,431	298	5.3	1.8%	89.4
	Medium	12,244	327	0.2	0.1%	89.1
ALL SDG&E		**13,675**	**624**	**5.5**	**0.9%**	**89.2**

SDG&E's customers show similar trends to the other two IOUs, with the largest impacts coming from the large customer group, and small, but positive impacts coming from the medium group.

Recommendations

AEG has developed three recommendations for future research and evaluation related to the non-residential CPP programs.

- Investigate the experiences of small and medium participants. While PY2020 saw improvements in the impacts among small and medium customers, we do not fully understand why the impacts improved. Several factors including, extreme weather, increased price sensitivity during COVID-19 conditions, and loss of bill protection are all possibilities. Future or ongoing process evaluations ensure that special care is taken to better understand the experiences of small and medium customers on the CPP rates and the various factors that contribute to their response. Participant surveys and focus groups can be used to understand aspects of participation including effects of extreme weather, effects of COVID-19 conditions, awareness and understanding of the rate, awareness of participation, awareness of events, ability to respond to events, and actions taken during events. Conducting research while maintaining statistically significant samples by key industry groups and size may provide invaluable insights for both program staff and future impact evaluations.
- Investigate the effect of notifications on customer impacts. Again, through the use of participant surveys and/or focus groups, conduct research to better understand participant choices regarding notification, their awareness of notifications, and how they respond to notifications on event days. It would also be of interest to know how those that elected not to receive notifications learn about events.
- Consider opportunities to improve robustness of within-subjects designs. For most of the subgroups, we elected not to develop a matched control group for this evaluation because of the small ratios of participants to non-participants and the opt-out nature of the CPP, or PDP, rates which would likely lead to poor matches and introduce self-selection bias. Unfortunately, the within-subjects design may also have led to the introduction of bias, particularly among those groups with very small impacts due to a lack of truly comparable event like days. Since all utilities expect their participant population to grow (and the non-participant pools to continue to shrink) we recommend considering the following opportunities to mitigate this bias in the future. We propose two options for consideration:
    - Intentionally call test events on cooler days and, unless absolutely necessary, try not to call events on all the hottest days of the season. This will provide the models with better information as to how participants would behave during events on a wider range of temperatures and improve their performance.
    - Consider developing a randomized EM&V group that could be used as a control during events. These customers might not be called to respond on all event days, or, might be called to respond on alternate days. This would significantly improve the ability of the evaluation to detect the true impact of the CPP program.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

This report documents the load impact evaluation of the non-residential Critical Peak Pricing (CPP) programs operated by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) for PY2020.

Research Objectives

This study's key objectives are to estimate both ex-post and ex-ante impacts for the non-residential CPP programs. More specifically,

- This report presents PY2020 ex-post impacts for the average participant and all participants in aggregate for each hour of each event day and the average event day for each IOU's CPP program. Ex-post results also include impacts at the program level and the following: size group, local capacity area (LCA), industry group, AutoDR and TA/TI, dually enrolled DR participants, and notified vs. non-notified participants.
- This report presents ex-ante impacts for each year over a 12-year[13] time horizon, based on each IOU's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day both at the program and portfolio level. Portfolio level impacts exclude the load impacts of customers dually enrolled in another DR program. Ex-ante results also include impact estimates at the program level and the following: size group, LCA (as appropriate), and busbar (as appropriate) for both an average participant and all participants in aggregate for all program operating hours and the resource adequacy (RA) window (4 PM to 9 PM).

Report Organization

The remainder of this report includes the following sections:

- Section 2 describes the CPP program implementation for each IOU and presents information regarding the total number of accounts enrolled in each program.
- Section 3 describes the methods used to estimate the ex-post and ex-ante impacts for the 2020 program year.
- Section 4 presents the ex-post impact evaluation results.
- Section 5 presents the ex-ante impact evaluation results.
- Section 6 presents key findings and recommendations.

[13] Eleven-year forecast for SCE.

2

PROGRAM DESCRIPTION

This section describes the CPP program implementation for each IOU in 2020 and any changes since PY2019. We also present information regarding the PY2020 event days, and the total number of participants at each utility, by industry.

Program Implementation

California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and charge higher rates during CPP events. These "dynamic" pricing rates encourage price-responsive demand reductions during the higher-priced events. Customers benefit financially from long periods of lower rates for electricity consumed outside of the CPP event periods. New customers on the program may also be eligible for bill protection for up to 12 months, during which time their energy costs on CPP do not exceed their costs under their previous tariff.

The CPP rate designs are similar across the three IOUs[14].

- All CPP tariffs are designed for bundled service customers.
- CPP participants are also eligible to participate in Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) programs.
- Newly enrolled customers receive bill protection for the first 12 months.

Other program attributes vary by utility, including the notification period for events, the specific hours when CPP events can be called, and the number and duration of CPP events. Table 2-1 summarizes key program parameters by IOU.

Table 2-1 Event Hours and Allowed Number of Events by Utility

Utility	Notification	Event hours	Events / year	Season
PG&E	Day-ahead before 2 PM	2 to 6 PM	9 to 15	Year-round
SCE	~ 24-hour notice	4 to 9 PM	12	Year-round/non-holiday weekends
SDG&E	Day-ahead before 3 PM	2 to 6 PM	Maximum of 18	Year-round

The three California IOUs began defaulting their large commercial and industrial customer accounts onto CPP rates twelve years ago. Specifically, SDG&E began their CPP default in 2008, followed by PG&E and SCE in 2010.[15] Small and Medium Business (SMB) customers have been able to participate voluntarily on CPP rates since 2014.

- By the end of 2016, SDG&E completed their default of all SMB customers onto the CPP rates.

[14] PG&E's CPP rate is referred to as Peak Day Pricing (PDP)

[15] Most of the defaulted customers were previously served under tariffs with TOU energy and/or demand charges, such that they already had varying incentives to reduce load during peak periods on all summer weekdays.

- In 2018, PG&E suspended their PDP default to allow customers time to adjust to the new Time-of-Use (TOU) period implemented between 2019 and 2020.
- SCE's default of SMB customers with demands below 200 kW, along with large pumping and agricultural customers, onto the CPP rate began in March 2019.

Table 2-2 below summarizes the groups of customers included in the ex-post and ex-ante portions of this study. Note that the SDG&E's small CPP customers are excluded from this study.

Table 2-2 Analyses included in Evaluation by Utility and Customer size

Size Group	PG&E	SCE	SDG&E
Large (≥ 200 kW)	*Ex-post* and *ex-ante*	*Ex-post* and *ex-ante*	*Ex-post* and *ex-ante*
Medium (20 ≤ x < 200 kW)	*Ex-post* and *ex-ante*	*Ex-post* and *ex-ante*	*Ex-post* and *ex-ante*
Small (< 20 kW)	*Ex-post* and *ex-ante*	*Ex-post* and *ex-ante*	Excluded[16]

Most of the largest customers at PG&E and SDG&E have the option of reserving a level of generation capacity (a capacity reservation level, or CRL) to protect a portion of their load on CPP event days.[17]

PY2020 Event Days

Table 2-3 below summarizes the CPP events called by each utility in PY2020. All events were called between May 27th and October 1st. Shown in red text are the weekend events called in PY2020. PG&E and SDG&E called one and three weekend events, respectively.

Table 2-3 PY2020 CPP Event Dates by Utility

Date	Day of Week	PG&E	SCE	SDG&E
May 27	Wednesday	X		
June 24	Wednesday	X		
June 25	Thursday	X		
July 8	Wednesday		X	
July 10	Friday		X	
July 13	Monday		X	
July 15	Wednesday		X	
July 20	Monday		X	
July 27	Monday	X		
July 28	Tuesday	X		
July 30	Thursday	X		
August 3	Monday		X	
August 4	Tuesday		X	
August 10	Monday	X		
August 12	Wednesday		X	

[16] Approximately 1,000 customers with maximum demands less than 20 kW were included in SDG&E's 20 to 200 kW group because they were participating on SDG&E's Medium CPP Tariff

[17] Effective March 2019, SCE no longer offers the CRL and CPP lite option.

Date	Day of Week	PG&E	SCE	SDG&E
August 13	Thursday	X	X	
August 14	Friday	X		
August 17	Monday	X	X	X
August 18	Tuesday	X	X	X
August 19	Wednesday	X	X	X
August 20	Thursday			X
September 5	Saturday			X
September 6	Sunday	X		X
September 7	Monday (Holiday)			X
September 30	Wednesday			X
October 1	Thursday			X
Total		**13**	**12**	**9**

Program Changes

Current (PY2020) and proposed program changes by IOU are as follows:

- PG&E
  - Current PDP customers that enroll in TOU-B before 2021 are unenrolled from PDP because PDP and TOU-B are not compatible until 2021.
  - Effective March 2021, the PDP event window is shifting to 5 to 8 PM.
  - Pending CPUC decision for R.20-11-003, the PDP event window is expected to be modified to 4 to 9 PM at a later point.
- SCE
  - Additional defaults occurred in October 2020, but this did not affect PY2020 ex-post impacts.
- SDG&E
  - In 2021 and 2022, SDG&E anticipates a substantial decrease in participants due to the migration of bundled customers to DA/CCA service.
  - SDG&E will be changing its CPP period to 4 to 9 PM. However, it may not be implemented until 2022 or 2023 as they are in the process of implementing a new billing system.

PY2020 Participant Counts

This section presents counts of participants by utility, industry type, and size category. It also includes information regarding what percent of the enrolled population received notification of events. The participant counts represent the participation on a typical event day; actual counts varied by event.

Table 2-4 presents the eight industry-type definitions and corresponding NAICS codes. Table 2-5 shows the number of service accounts enrolled in CPP, or PDP, during a typical summer event by industry and utility. Table 2-6 presents the number of service accounts enrolled in CPP, or PDP, during a typical summer event by size group, small (< 20 kW), medium (20 kW ≤ x < 200 kW), and large (≥ 200 kW).

Table 2-4 Industry Type Definitions

Industry Type	NAICS Codes
1. Agriculture, Mining & Construction	11, 21, 23
2. Manufacturing	31-33
3. Wholesale, Transport, Other Utilities	22, 42, 48-49
4. Retail Stores	44-45
5. Offices, Hotels, Finance, Services	51-56, 62, 72
6. Schools	61
7. Institutional/Government	71, 81, 92
8. Other/Unknown	NA

Table 2-5 Enrolled Service Accounts, by Utility and Industry Group, Typical Event Day

Industry Type	PG&E	SCE	SDG&E
1. Agriculture, Mining & Construction	6,667	11,196	418
2. Manufacturing	4,555	10,953	1,149
3. Wholesale, Transport, Other Utilities	17,093	14,163	904
4. Retail Stores	9,583	33,257	1,770
5. Offices, Hotels, Finance, Services	34,648	110,076	6,592
6. Schools	2,256	3,020	736
7. Institutional/Government	20,431	32,949	1,810
8. Other/Unknown	6,397	28,477	297
Total	**101,629**	**244,091**	**13,675**

Table 2-6 Enrolled Service Accounts, by Utility and Size Group, Typical Event Day

Size Group	PG&E	SCE	SDG&E
Large (≥ 200 kW)	865	1,895	1,431
Medium (20 kW ≤ x < 200 kW)	13,914	29,581	12,244
Small (< 20 kW)	86,850	212,615	-
Total	**101,629**	**244,091**	**13,675**

It is also important to keep in mind that not all the customers enrolled in CPP, or PDP, received communication regarding events. As customers defaulted onto the rates, each utility established mechanisms to reach out to customers to obtain contact information to provide day ahead event notification. However, while customers may not have elected to receive notification via text or email, the IOUs also provide event alerts on mobile DR apps, utility websites, and social media. Table 2-7 shows the percentage of participants notified by utility and size group on a typical event day.

Table 2-7 Percent of Service Accounts Receiving Notification, by Utility and Size Group, Typical Event Day

Size Group	**PG&E % Notified**	**SCE % Notified**	**SDG&E % Notified**
Large (≥ 200 kW)	87%	81%	63%
Medium (20 kW ≤ x < 200 kW)	87%	86%	48%
Small (< 20 kW)	84%	86%	-
Total	**84%**	86%	**50%**

3

STUDY METHODS

This section presents the methods used to estimate the ex-post and ex-ante impacts for the three IOUs' CPP programs.

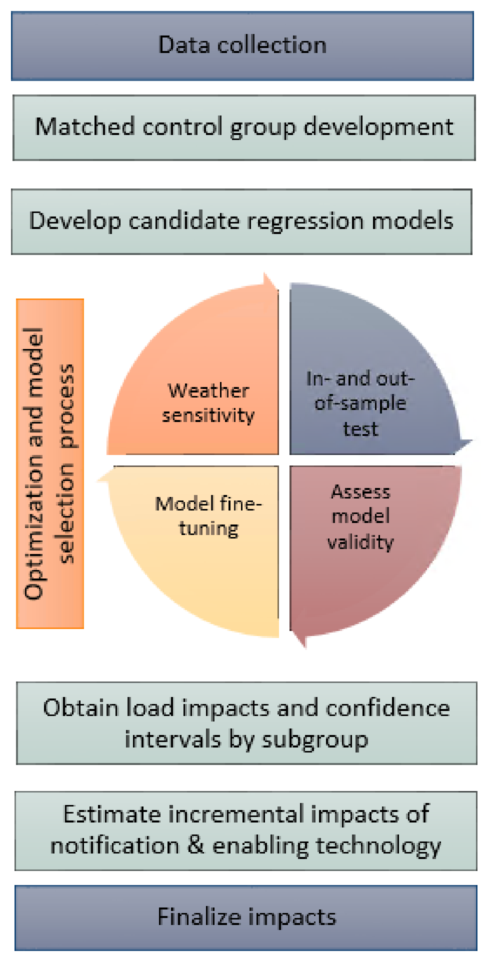
Ex-Post Impact Analysis

The primary objectives of the ex-post analysis follow.

For each of the three IOUs, at both the aggregate and per-participant levels, the objectives include to:

- Develop hourly and daily load impact estimates for each CPP event day called in PY2020 for the following:
    - PG&E large customers (≥ 200 kW) and Small-to-Medium Business (SMB) customers (< 200 kW),
    - SCE large non-residential customers (≥ 200 kW), and SMB customers (< 200 kW), and
    - SDG&E large customers (≥ 200 kW) and medium customers (20 kW ≤ x < 200 kW).
- Provide estimates by various segments: LCA, industry group, dual enrollment in other DR programs, Auto DR or TA and TI, and other industrial classifications such as busbar.
- Estimate the effect of utility notification of events.

Figure 3-1 Ex-Post Analysis Approach



Overview of AEG's Approach

AEG's approach to the ex-post analysis is summarized in Figure 3-1. The key points we would like to highlight in our approach are as follows:

- Utilized a within-subjects approach or a matched control group. For subgroups where it was feasible, AEG developed a matched control group. AEG employed a within-subjects design for subgroups where it was not feasible, leveraging event-like days in 2019. Table 3-1 presents the methodology used to estimate impacts for each subgroup.
- Estimated subgroup level models for each IOU, size, and industry. The purpose of subgrouping is to minimize variation in the models while eliminating the need for customer-specific models, which is unfeasible given the number of participants in CPP. All subgroup level models were ultimately selected using our optimization process combined with industry expertise and experience.

- Estimated customer-specific models for a small subset of extremely large (x-large) customers. Based on lessons learned from the PY2019 LI analysis, AEG utilized customer-specific models for extremely large[18] customers. This approach will also minimize variation in the aggregate models and allow for better impact estimates. All customer-specific models were selected using our optimization process used primarily in our Statewide Capacity Bidding Program LI evaluations.

Table 3-1 presents the methodology employed by utility and size group. We based the methods on the total non-participant to participant ratio in each group. In general, a non-participant to participant ratio of at least 3 to 1 is required to obtain a good match; therefore, we employed a within-subjects design for groups with a ratio less than three.[19] The within-subjects design leverages participant loads on event-like days to estimate the reference load.

Table 3-1 Analysis Method by Subgroup

Utility	Size Group	Analysis Method
PG&E	Small	Within Subjects
	Medium	Within Subjects
	Large	***Matched control; Customer-specific for top 10%***
SCE	Small	**Within Subjects**
	Medium	**Within Subjects**
	Large	***Matched control; Customer-specific for top 5%***
SDG&E	Medium	Within Subjects
	Large	Within Subjects

The ex-post analysis is conducted independently for each IOU. However, AEG used the same set of candidate models and optimization strategies across all three IOUs to maintain consistency in the results while allowing for customization.

Detailed Description of Methods

In the subsections that follow, we describe the analysis steps in more detail.

Data Collection

To address each of the load impact objectives, AEG collected the following types of data:

- Customer information for the CPP customers and potential control group customers (e.g., industry group, weather station, LCA, size group),
- Monthly billing data for CPP customers and potential control group customers,
- Billing-based interval load data (i.e., hourly loads) for sampled CPP customers and potential control group customers,
- Weather data (i.e., hourly temperatures and other variables for the relevant time period, by weather station),
- Program event data (i.e., dates and hours of CPP events and any programs in which CPP customers are dually enrolled),

[18] "Extremely large" customers were determined by participants' average daily loads. For PG&E, this was determined to be customers in the 90th percentile or top 10% of PG&E Large customers. For SCE, this was determined to be customers in the 95th percentile or top 5% of SCE Large customers.

[19] In addition to having small non-participant pools, the potential control group customers for the defaulted groups are made up of customers that opted out of the CPP rate. They are likely to be different than those that stayed on the rate and may introduce substantial self-selection bias into the analysis.

- Notification data for each participant on each event day.

Sample Selection

In the interest of efficiency, AEG utilized a sampling approach to limit the amount of data requested and received. Since regression models will be estimated at subgroup levels for each IOU, size, and industry, the sample was designed based on this subgrouping. For PG&E and SCE, we pulled a sample of 5,000 customers from the following subgroups:

- PG&E
  - Small: Wholesale/Transport/Utilities, Retail stores, Offices/Hotels/Finance/Services, Institutional/Government, and Other
- SCE
  - Small: Agriculture/Mining/Construction, Manufacturing, Wholesale/Transport/Utilities, Retail stores, Offices/Hotels/Finance/Services, Institutional/Government, and Other
  - Medium: Retail stores and Offices/Hotels/Finance/Services

For PG&E and SCE's subgroups not mentioned above and all SDG&E subgroups, a census sample was utilized.

Event-like Days Selection

The selection of comparable non-event days, or event-like days, is essential to several of the evaluation activities. These were used in the matched control group development and the out-of-sample testing in model optimization.

The event-like days included 5 to 15 days which are comparable to called event days in weather, day of the week, and month of the year. We used a Euclidean distance metric[20] (similar to what we describe in matched control group development) to select days that are as similar as possible to actual event days using multiple weather-based criteria.

Matched Control Group Development

To create the matched control groups, we used a Stratified Euclidean Distance Matching (SEDM) technique. The basic steps were as follows:

Step 1 is to define both the participant and non-participant populations and the treatment and pre-treatment periods for each participant. Once the participant and non-participant populations are identified, both populations can be assigned to strata or filters that are categorical in nature. For CPP participants, we used size and industry type as key filters. This ensured that customers with similar usage characteristics were matched to one another, capturing some of the unobservable attributes that affect the way customers use energy.

Step 2 is to perform the one-to-one match based on hourly demand data of comparable event-like days. To determine how close each participant is to a potential match, we used a Euclidean distance metric. The

[20] We included three weather variables in the Euclidean distance metrics calculation to select similar non-event days: (1) daily maximum temperature; (2) daily minimum temperatures; and (3) average daily temperature. We will work with each IOU to determine which weather variables are best suited for selecting days that are most similar to event days. In PY2019, the Euclidean distance metric used was calculated by the following equation:

$$ED = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2 + (MinTemp_{event} - MinTemp_{non-event})^2 + (MeanTemp_{event} - MeanTemp_{non-event})^2}$$

Euclidean distance is defined as the square root of the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance. For this one-to-one match, we included three demand variables:

- The average demand on event-like days during the event window,
- The demand on event-like days during the typical system peak hour (HE18),
- And the average demand on event-like days during the hours outside the event window.

We then weighted the variables to reflect the relative importance of the estimates, with typical system peak hour having the most weight and the average demand outside the typical event window having the least weight. The Euclidean distance for this set of variables can be calculated using the equation below.

$$ED = \sqrt{\begin{array}{c} w_1(avgevnt_{Ti} - avgevnt_{Ci})^2 + w_2(systempeak_{Ti} - systempeak_{Ci})^2 \\ + w_3(avgnonevnt_{Ti} - avgnonevnt_{Ci})^2 \end{array}}$$

After calculating the distance metric within each group for each possible combination of participant and control customer, the control customer with the smallest distance is matched to each participant without replacement. We can then select the closest matches[21] for each of our participants, creating a one-to-one match of control customers to participants. Once the matching process is complete, we validate the match by using the appropriate t-tests and visual inspection of the event-like day load shapes.

Develop Candidate Regression Models

Given the evaluation timeline, it would be difficult to develop models individually for the 64 industry and size subgroups and the approx. 200 x-large participants across the three IOUs. Therefore, we developed a set of candidate models which were fit to all subgroups and x-large participants and utilized an algorithm developed in previous Statewide DR evaluations to select the best model for each subgroup.

We can think of regression models as being made up of building blocks, which are in turn made up of one or more explanatory variables. These different sets of variables can be combined in different ways to represent different types of customers. The blocks can be generally categorized into either "baseline" variables, or "impact" variables and could be made up of a single variable (e.g., cooling degree hours, CDH), or a group of variables (e.g., days of the week). The baseline portion of the model explains variation in usage unrelated to demand response events, while the impact portion explains the variation in usage related to a DR event.[22]

The candidate models fit into two basic categories:

- Weather sensitive models which include weather effects and calendar effects.
- Non-weather sensitive models that include the morning load adjustment and calendar effects.

Table 3-2 below presents the listing of the different variables and variable combinations we used to develop the candidate models.

[21] The closest match is defined by a control customer with an ED with the smallest distance to a participant's ED. If two or more participants share the same closest match, the participant that is "worst off" will "win" its closest match. This is determined by checking the ED's for the second closest matches for each participant.

[22] Any unexplained variation will end up in the error term.

Table 3-2 Variables Included in Candidate Regression Models

Type of Variable	Variable	Description
Dependent	kWh $_{i,t}$	Hourly consumption for customer *i* in hour/day *t*
Baseline Fixed effect	α_{i}	Indicator variable for each customer *i*
Baseline Calendar	Day of Week $_{t}$	Indicator variable for each day of the week
Baseline Calendar	Weekday $_{t}$	Indicator variable taking on the value of 1 for each weekday and 0 for weekends and holidays
Baseline Calendar	Month of Year $_{t}$	Indicator variable for each month of the year
Baseline Weather	CDH $_{i,t}$	Cooling degree hours[23] for customer *i* in hour/day *t*
Baseline Weather	Meantemp $_{i,t}$	Mean temperature for customer *i* on day *t*
Baseline Adjustment	Average Load $_{i,t}$	Average hourly load for a specified window[24] for customer *i* on day *t*
Baseline Adjustment	Other DR $_{i,t}$	Indicator variable that takes on a value of 1 if a customer *i* is dually enrolled and participated in another DR event on day *t*
Impact	Event $_{i,t}$	Indicator that takes on a value of 1 if customer *i* participated in an event on day *t*
Impact Interaction	(Event * Weekday) $_{i,t}$	Interaction between event and weekday for customer *i* on day *t*
Impact Interaction	(Event * Notification) $_{i,t}$	Interaction between event and notification that takes on a value of 1 if customer *i* was notified of an event on day *t*
Impact Interaction	(Event * CDH) $_{i,t}$	Interaction between event and CDH for customer *i* on day *t*
Impact Interaction	(Event * month) $_{i,t}$	Interaction between event and month for customer *i* on day *t*

Various combinations of the variables above resulted in 24 potential candidate models.

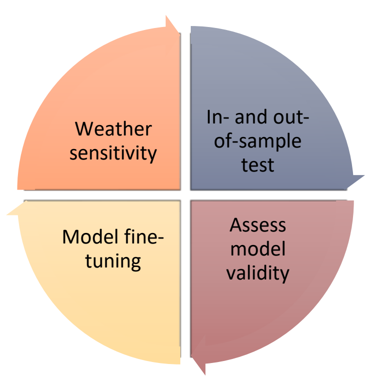
Optimization and Model Selection Process

Our optimization process incorporates the validation of the subgroup regression models. The subgroup models are designed to:

- Accurately predict the actual participant load on event days, and
- Accurately predict the reference load, or what participants would have used on event days in absence of an event.

To meet these two specific goals, our optimization process included a four-part cycle consisting of the following steps: (1) assessing weather sensitivity; (2) in-sample and out-of-sample testing; (3) assessing model validity; and, (4) model fine-tuning.

Figure 3-2 Optimization Process



1. Assess Weather Sensitivity. To increase efficiency in the model selection process, we

[23] Depending on the service territory, base temperatures can be one or more of the following: 60, 70, 80, 85, 95.

[24] The specified window can be one or more of the following: HE5-HE10, HE11-HE13, HE13-HE16, HE21-HE23.

first assessed weather sensitivity by performing p-value tests on coefficient estimates on weather variables. This test determined if each customer or subgroup will be tested on weather sensitive or non-weather sensitive models during the optimization process. Performing this first step cut down the model optimization process, since we did not need to run subgroups and customers through all candidate models. This is extremely valuable given the number of participants in CPP, across all three IOUs.

2. In-Sample and Out-of-Sample Testing. We used in-sample tests to show how well each model performs on the actual event days. This tests how well the model is able to match the actual load. We used out-of-sample tests to show how well each of the candidate models could predict a customer's load on non-event days that were as similar as possible to actual event day; this tests how well each model could predict the reference load.

- To perform the in-sample test, we fitted each candidate model to the entire data set. The results of these fitted models are used to predict the usage on event days. Then we assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE)[25] and mean percent error (MPE)[26], respectively. We refer to these metrics as the in-sample MAPE and MPE.
- To perform the out-of-sample test, we first identified the out-of-sample event-like days as several days that are similar to event days. For efficiency and consistency, we used the same event-like days used in matched control group development. After identifying the event-like days, event-like days are removed from the analysis dataset and the candidate models are fitted to the remaining data. Lastly, we assessed the accuracy and bias of the predictions by calculating the MAPE and MPE, respectively. Similarly, we refer to these metrics as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. Recall that the goal of the tests is to find the best model for each subgroup in terms of its ability to predict the reference load and the actual load for each subgroup. Therefore, for each subgroup, we combined the two tests into a single metric, giving each candidate model a single metric. The metric is defined in as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + \big(0.1 * abs(MPE_{in})\big) + \big(0.1 * abs(MPE_{out})\big)$$

Once we have a single metric for each subgroup and candidate model combination, we selected the best model for each subgroup by choosing the model specification with the smallest overall metric.

[25] The mean absolute percent error (MAPE) is defined as: $MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right|$

[26] The mean percent error (MPE) is defined as: $MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h}$

3. Assessing Model Validity. After selecting the best model for each subgroup by minimizing the smallest overall metric, AEG assessed model validity at the program level. We did this by calculating the weighted average MAPE and MPE at the program level. For both metrics, we like them to be low or very close to zero to be able to say that all the subgroup best models collectively deliver good levels of accuracy and bias. We describe the steps in more detail and go over program metrics in the model validity subsection (see Appendix B).
4. Model Fine-Tuning. We also routinely use visual inspection of the results as a simple but highly effective tool. During the inspection, we looked for specific aspects of the segment-level predicted and reference load shapes to determine how well the models perform. We used observations derived from these inspections to make necessary edits to the model specifications obtained from the optimization process. For example:

- We checked to make sure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate that there is a problem with the reference load either over or under estimating usage in absence of the rate.
- We closely examined the reference load for odd increases or decreases in load that could indicate an effect that is not properly being captured in the model.
- We also looked for bias both visually and mathematically. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

Obtain Load Impacts and Confidence Intervals by Segment

The following example illustrates the process of estimating the impacts from the final model for a single subgroup. In the entire analysis, there were ultimately 64 subgroups and approx. 200 x-large participants, each with their own final model specification determined by the optimization process (see Appendix B). Nevertheless, the process will be the same in each case.

Let's assume that this subgroup is weather sensitive and that the final model specification includes calendar and weather effects in the baseline portion of the model. In this simple example below, α_t, δ_t, and CDH_t, make up the baseline blocks of the model, and explain variation in kwh_t unrelated to demand response events. The remaining variables, $EVNT$, and the interaction term $(\alpha_t * EVNT)$ are the impact blocks and explain the variation in kwh_t related to a DR event.[27] An hourly model like equation (1) below can be equivalently estimated as one model with hourly dummy variables, or as 24 separate hourly models.

$$kwh_{it} = \beta_0 + \alpha_t + \delta_t + CDH_t + EVNT + (\alpha_t * EVNT) + \varepsilon_{it} \quad (1)$$

Where:

kwh_{it} is the consumption of customer i in hour t

β_0 is the intercept

α_t is a vector of segment indicators, i.e. AutoDR, LCA, etc.

δ_t is a vector of calendar variables, i.e. month, year, and day of week

CDH_t represents the cooling degree hours for hour t

$EVNT$ is a dummy variable indicating that hour t was on a CPP or PDP event day

$(\alpha_t * EVNT)$ is an interaction between the event indicator and the segment indicator variables

ε_{it} is the error for participant i in time t

This type of time-series data is likely to have both autocorrelation and heteroskedasticity. To address autocorrelation, we utilize two techniques: (1) estimate 24 separate models for each hour to remove autocorrelation from hour-to-hour; and (2) incorporate seasonal indicators to minimize autocorrelation. To address heteroskedasticity, we simply use the Huber-White robust error correction.

We used the model above to estimate the load impacts as follows:

- First, we obtained the actual and predicted load for each participant on each hour and day based on the specification defined in equation (1).
- Next, we used the estimated coefficients and the baseline portion of the model to predict what this participant would have used on each day and hour, if there had been no events. We call this prediction the reference load.
- We calculated the difference between the reference load (the estimate based on the baseline blocks) and the predicted load (the estimate based on the baseline + impact blocks) on each event day. This difference represents our estimated load impact for each participant.

To show the actual observed load (and avoid confusion associated with the predicted load) we re-estimated the reference load as the sum of the observed load and the estimated load impact.

Because the impacts are statistical estimates, it is important to establish a range or confidence interval around the estimates resulting in the uncertainty adjusted load impacts required by the Protocols. We utilized a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each participant. Then, because we can assume that the customer-specific estimates are independent across participants, the variance of the sum is the sum of the variances. A similar process is repeated to obtain confidence intervals for each segment.

[27] Any unexplained variation will end up in the error term.

Ex-Ante Impact Analysis

The main goal of the ex-ante analysis is to produce an annual twelve-year[28] forecast of the load impacts expected from the CPP programs. Separate forecasts are to be produced for each LCA (as applicable), each busbar (as applicable), and bundled v. direct access (as applicable). We produced a set of impacts under each of the required weather scenarios: monthly peak day and typical event day for 1-in-2 weather year and 1-in-10 weather year for each of the IOUs and the CAISO. A portfolio forecast that excludes the forecasted load impacts of dually enrolled customers is also provided. An annual twelve-year forecast was produced for each of the following:

- PG&E large customers (≥ 200 kW) and SMB customers (< 200 kW);
- SCE large non-residential customers (≥200 kW) and SMB non-residential customers (< 200 kW); and,
- SDG&E large customers (≥ 200 kW) and medium customers (20 kW ≤ x < 200 kW).

Our approach achieved these goals by determining the appropriate weather-adjusted and COVID-adjusted, reference load and per-customer impacts for each of the segments of interest, and then multiplying that impact by the number of participants for each year specified by the enrollment forecast.

First, we describe the various steps involved in implementing this approach in detail. Then we address uncertainty in the forecast and the calculation of confidence intervals. The figure below provides an overview of the ex-ante analysis approach including the four key steps of the analysis. Estimation of the reference load is presented in teal, estimation of the load impacts is presented in yellow, and application of the enrollment forecast is highlighted in orange.

[28] Eleven-year forecast for SCE.

Figure 3-3 Overview of the Ex-Ante Analysis Approach

Create Annual Weather-Adjusted Reference Load

- Estimate the weather-adjusted per customer reference loads using the coefficients from the ex-post models and inputs from the weather scenarios.
  - Where winter data is unavailable (SCE only), non-summer impacts are based on June data calibrated to reflect seasonality.

Apply the COVID adjustment to Reference Load

- The effect of COVID-19 conditions is estimated for each size group using a simple regression approach.
- Apply the effect to the reference load using IOU-specific factors to remove the effect of COVID-19 conditions over time.

Calculate the Per Customer Load Impacts

- Estimate the weather-adjusted per customer load impacts using the coefficients from the ex-post models and inputs from the weather scenarios.
- Incorporate the COVID adjustment by calculating the new load impacts as a percent of the new (COVID-adjusted) reference load.

Apply the enrollment forecast

- Assume zero impacts for 1st year defaulted small and medium customers (SCE only).
- Multiply annual per customer impacts by enrollment forecast to arrive at aggregate forecast.

Detailed Description of Methods

In the subsections that follow we describe the analysis steps in more detail.

Weather-Adjusted and COVID-Adjusted Reference Loads

Comparisons of PY2020 results to previous program years showed that the effect of COVID-19 conditions are primarily found on the reference load or customers' overall usage. For non-residential customers, this was a decrease in average customer loads. The ex-post analysis showed changes and improvements to program impacts, however, this could also be attributed to several other factors that occurred in PY2020.

The weather adjusted reference load is estimated using an approach similar to that used in previous evaluations. It is described below as a part of the process used to develop the weather-adjusted per-customer impacts. New to the PY2020 ex-ante analysis is the incorporation of the effect of COVID-19 conditions. The first step was to directly estimate the average COVID effect for each IOU and size group using a simple regression model taking the basic form of equation 2 below.

$$kwh_{it} = \beta_0 + \delta_t + CDH_t + EVNT + COVID + \varepsilon_{it} \quad (2)$$

Where:

kwh_{it} is the aggregate average event window consumption of group i on day t

β_0 is the intercept

δ_t is a vector of calendar variables, i.e. month, year, and day of week

CDH_t represents the cooling degree hours for day t

$EVNT$ is a dummy variable indicating that hour t was on a CPP or PDP event day

$COVID$ is a dummy variable indicating that day t was in the COVID period, after March 15th, 2020

ε_{it} is the error for group i on day t

The coefficient on the COVID effect tells us, on average, how much the event window consumption changed during the COVID period.

We applied this effect in two different ways depending on IOU.

- For SCE and PG&E, the COVID effect is added back to the weather-adjusted reference load to create a no-COVID case. Then IOU-specific factors are applied to the forecast to remove the COVID effect over time. We use this approach because PG&E and SCE provided AEG with an estimate of how much COVID-19 conditions would continue to affect the load forecast relative to a no-COVID case.
- For SDG&E, the COVID effect is first adjusted based on SDG&E's forecasting team's estimate of what percent of the COVID effect will remain in each month. Then, the effect is applied directly to the reference load to bring the load back to a no-COVID case over time.

Each IOU provided their own estimates of how quickly reference loads would return to the no-COVID case. The results of the COVID adjustment to the reference loads are presented at the beginning of each IOU's ex-ante section.

Per-Customer Load Impacts

The first step in the ex-ante analysis was to use the ex-post regression models to predict weather-adjusted impacts for each segment of interest. This will produce a set of impacts under each of the required weather scenarios. To do this, we carried out the following steps:

- For each program, the analysis begins with the coefficients estimated in the subgroup regression models developed for the ex-post analysis.
- Then, the actual weather from the program year is replaced with the 1-in-2 and 1-in-10 weather data to predict a customer's load for each of these scenarios assuming no events are called. The result was a weather-adjusted reference load for each customer for each weather scenario required.
- Next, the weather-adjusted event day load is predicted by again applying the coefficients from the ex-post models to both the 1-in-2 and 1-in-10 weather data. However, this time we assumed that events were called by changing the event indicator variables from zero to one.
- The weather-adjusted load impact for each customer is calculated by subtracting the weather-adjusted event-day load from the weather-adjusted reference load.

- For PY2020, we calculated the COVID-adjusted load impacts as a percent[29] of COVID-adjusted reference loads. This will allow the impacts to increase proportionally to the reference loads as usage returns to a no-COVID case.

Generation of Per-Customer Average Impacts by Segment

Once weather-adjusted and COVID-adjusted impacts were predicted for each customer and for each of the desired weather scenarios, it became a relatively simple exercise to average the individual impacts and generate per customer average impacts by segment of interest.

Since we are dealing with very small, sometimes insignificant, impacts in the small and medium customer groups, we performed an additional check on the average event window impacts, checking for negative weather-adjusted impacts. These small negative impacts are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. We have no reason to think that customers are increasing their load in response to events. For these cases wherein we found negative average event window impacts, we set the estimates to zero. Note that negative average impacts in the RA window for PG&E and SDG&E are plausible given that the RA window coincides with post-event hours wherein snapback effects are likely to occur.

Creation of 12-Year[30] Annual Load Impact Forecasts

The next step in the analysis will be to use the set of per-customer average impacts to create an annual forecast of load impacts over the next 12 years. For PG&E and SCE, the 2020 ex-post weather adjusted per-customer subgroup level impacts were multiplied by the number of customers in each IOU's enrollment forecast by month and year to develop the 12-year load forecast.

[29] Percentage is determined using the weather-adjusted estimates, i.e., weather-adjusted load impacts divided by weather-adjusted reference loads.

[30] Eleven-year forecast for SCE.

4

EX-POST RESULTS

This section presents the ex-post impacts for each IOU by size, industry, LCA, dual participation, participation in Auto DR or TA/TI, and receipt of event notification for the 2020 CPP, or PDP, programs.

PG&E

This section presents the ex-post load impact analysis for PG&E. The primary load impact results include estimates of average event-hour load impacts, aggregate and per-customer, for the typical event day (which is simply the average of all the event days) and for each event. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

Table 4-1 below summarizes the overall program level event-hour impacts on each event including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Note that in PY2020, PG&E called a weekend event (September 6th).

Table 4-1 PG&E All Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	101,544	789.5	16.3	7.8	0.2	2.06%	95.5
June 24	101,605	806.1	18.8	7.9	0.2	2.33%	92.0
June 25	101,608	813.7	15.4	8.0	0.2	1.89%	93.0
July 27	101,631	773.0	16.7	7.6	0.2	2.16%	91.3
July 28	101,632	783.2	15.1	7.7	0.1	1.92%	91.9
July 30	101,634	781.1	15.2	7.7	0.1	1.95%	91.6
August 10	101,642	810.9	16.7	8.0	0.2	2.06%	92.2
August 13	101,644	811.4	14.5	8.0	0.1	1.79%	93.6
August 14	101,644	860.8	17.8	8.5	0.2	2.06%	99.3
August 17	101,646	876.0	18.9	8.6	0.2	2.15%	96.2
August 18	101,647	893.9	17.8	8.8	0.2	1.99%	98.8
August 19	101,648	836.9	16.7	8.2	0.2	2.00%	95.6
September 6	101,656	654.4	9.3	6.4	0.1	1.43%	102.1
Typical Event Day	**101,629**	**807.0**	**16.1**	**7.9**	**0.2**	**1.99%**	**94.8**

Comparison of Ex-Post Impacts

In Table 4-2 and Table 4-3 below we present the comparison of current ex-post impacts to previous ex-post impacts, and current ex-post impacts to prior ex-ante impacts. These comparisons give the reader with a sense of how the program has performed over time, and how the program has performed relative to the most recent forecast.

Table 4-2 PG&E Non-Residential PDP: Previous and Current Ex-Post, Typical Event Day

Program Year	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
2019	Large	1,246	472.1	13.7	378.9	11.0	2.91%	97.5
	Medium	24,994	571.5	-0.1	22.9	<0.1	-0.02%	96.1
	Small	91,156	182.4	0.6	2.0	<0.1	0.35%	95.2
	All	**117,397**	**1,226.0**	**14.3**	**10.4**	**0.1**	**1.16%**	**96.2**
2020	Large	865	220.2	7.7	254.6	8.9	3.49%	96.4
	Medium	13,914	382.6	4.6	27.5	0.3	1.21%	95.9
	Small	86,850	204.2	3.8	2.4	<0.1	1.85%	92.5
	All	**101,629**	**807.0**	**16.1**	**7.9**	**0.2**	**1.99%**	**94.8**

Table 4-2 above, presents the ex-post from PY2019 compared to PY2020. PG&E's non-residential PDP program has decreased in participants, but increased slightly in total impacts, and percent impacts over relative to PY2019. In addition, it is important to note that PG&E's PDP population experienced a significant migration from the large group to the medium group and from medium to small.[31] We suspect this influx of larger customers in to the medium and small groups are in large part responsible for the increase in impacts.

Across all three IOUs the weather was more extreme in PY2020. While the overall average temperatures were similar across the whole summer relative to PY2019, a significant heatwave hit the state in late August and early September bringing record temperatures. For weather sensitive customers the increased heat also resulted in increased impacts. Additionally, having more extreme days in our underlying data allowed for more accurate modeling of weather relationships which may also have contributed to the increase impacts. PG&E's average temperature on a typical event day in PY2020 was 95° F vs. 94° F in PY2019. Additionally, the maximum average event temperature was 103 vs 96° F in PY2020 vs. PY2019.

It is also possible that COVID-19 conditions may have affected how customers responded to CPP events. Given the depressed economic conditions across the country, it is possible that participants had additional incentive to save energy (and money) over the summer of 2020. Also reduced capacities at many retail and restaurant locations may have facilitated additional response.

In Table 4-3 below, we present the PY2020 ex-post impacts compared to prior ex-ante impacts. Overall, total MW impacts are similar between the two forecasts although, as noted above, the impacts are spread differently across the size groups given the PY2020 migration.

[31] It is unclear whether the migration between customer size groups is a result of COVID conditions or, a result of some reclassification efforts on PG&E's side. Therefore, we maintain the existing size group distribution of participants througho ut the ex-ante forecast.

Table 4-3 PG&E Non-Residential PDP: Previous Ex-Ante (PG&E 1-in-2, Typical Event Day, 2020) and Current Ex-Post (Typical Event Day), 2 PM to 6 PM

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante	Large	1,254	419.3	13.7	334.4	10.9	3.26%	98.1
	Medium	24,302	553.6	0.8	22.8	<0.1	0.14%	98.1
	Small	87,561	173.4	0.6	2.0	<0.1	0.32%	97.1
	All	**113,117**	**1,146.3**	**15.0**	**10.1**	**0.1**	**1.31%**	**97.4**
Current Ex-Post	Large	865	220.2	7.7	254.6	8.9	3.49%	96.4
	Medium	13,914	382.6	4.6	27.5	0.3	1.21%	95.9
	Small	86,850	204.2	3.8	2.4	<0.1	1.85%	92.5
	All	**101,629**	**807.0**	**16.1**	**7.9**	**0.2**	**1.99%**	**94.8**

Results for Large Customers (≥ 200 kW)

This section summarizes the results for large PG&E program participants, defined as customers with maximum demand equal to or greater than 200 kW. The results are presented as follows:

- Average event-hour impacts for each event day,
- Hourly load impacts for a typical event day, and
- Average event-hour impacts on a typical event day by industry group and LCA.

Results for dually enrolled customers, AutoDR customers, and those notified (vs. not notified) are presented in subsequent subsections.

Figure 4-1 presents the average event-hour ex-post load impacts for each event day for all of PG&E's large PDP participants. The green bars indicate the magnitude of the aggregate load impact, and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

These results indicate that large customers had statistically significant load reductions on all thirteen event days, ranging from 6.1 to 10.3 MW. The average load impact was 7.7 MW.

Figure 4-1 PG&E Large all Participants: Average Event-Hour Impacts by Event

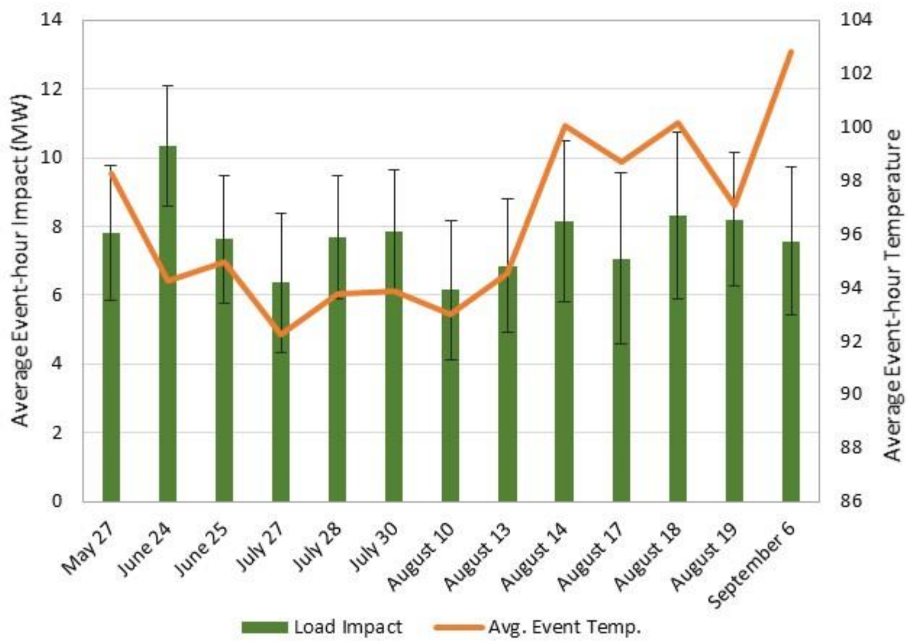


Table 4-4 summarizes the event-hour impacts on each event, including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Load impacts as a percent of the reference load were 3.49% on average across the thirteen events. Enrollment grew slightly over time ranging from 858 during the first event on May 27th to 867 participants on the last September 6th event.

In addition, it is interesting to note that while there is fluctuation from event to event, most of the error bars overlap indicating few significant differences between events.

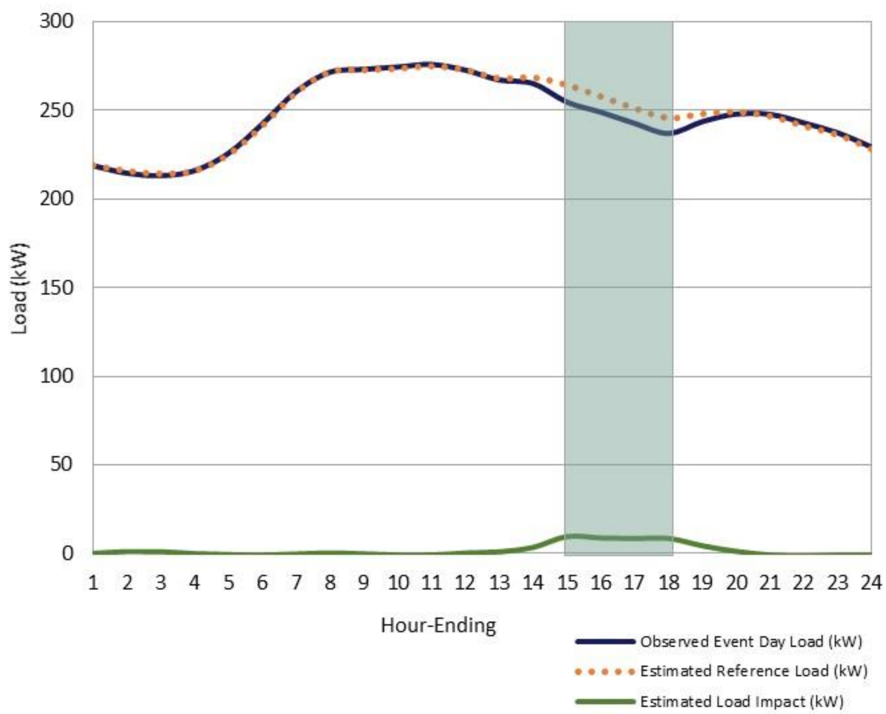
Table 4-4 PG&E Large all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	858	217.9	7.8	253.9	9.1	3.59%	98.3
June 24	860	219.5	10.3	255.2	12.0	4.71%	94.3
June 25	860	221.0	7.6	257.0	8.9	3.45%	95.0
July 27	866	215.3	6.4	248.6	7.3	2.95%	92.3
July 28	866	217.6	7.7	251.2	8.9	3.53%	93.8
July 30	866	219.2	7.9	253.1	9.1	3.59%	93.8
August 10	867	222.5	6.1	256.7	7.1	2.76%	93.0
August 13	867	230.6	6.9	266.0	7.9	2.97%	94.5
August 14	867	230.7	8.1	266.1	9.4	3.53%	100.1

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	867	234.7	7.1	270.7	8.1	3.01%	98.7
August 18	867	234.6	8.3	270.6	9.6	3.55%	100.2
August 19	867	228.5	8.2	263.6	9.5	3.59%	97.1
September 6	867	170.9	7.6	197.2	8.7	4.42%	102.8
Typical Event Day	**865**	**220.2**	**7.7**	**254.6**	**8.9**	**3.49%**	**96.4**

Figure 4-2 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. The highest load impact tends to occur during the first event hour. In addition, hourly load impacts do not show evidence of pre-cooling or post-event snapback. This shape is typical of large participants that tend to be less weather-sensitive and participate using a mix of end-uses rather than being cooling-dominated like SMB or residential customers. The load impacts outside the event windows are minimal and do not suggest that large customers respond to events by shifting event-hour loads to hours outside the event window.

Figure 4-2 PG&E Large all Participants: Hourly Typical Event Day Load Impacts



PG&E Large: by Industry

Next, we look at load impacts for PG&E large customers by industry group. Table 4-5 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Insignificant impacts are highlighted in red font.

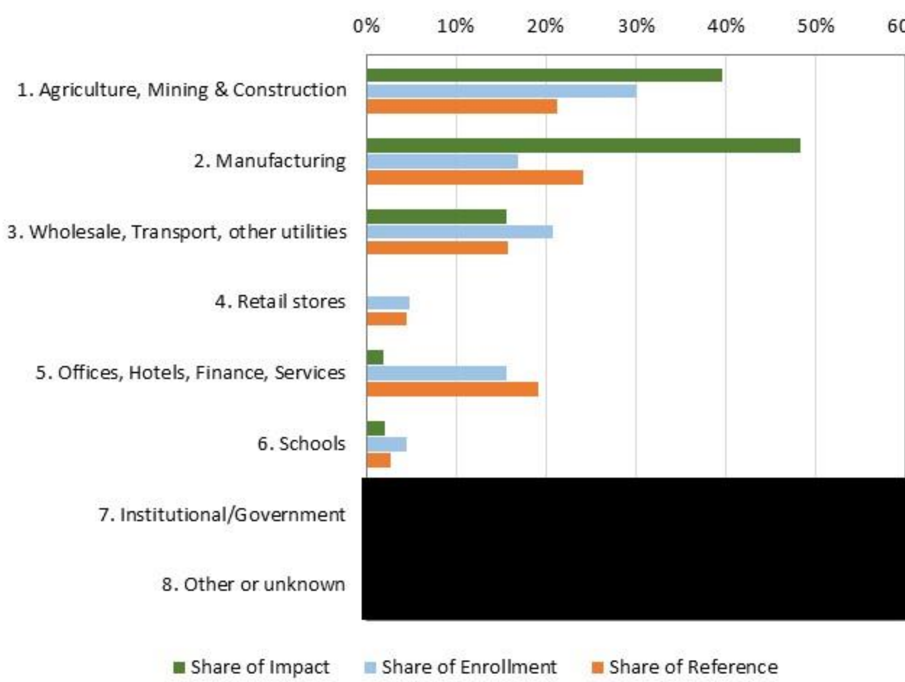
The largest estimated load impacts are from Manufacturing and Agriculture, Mining and Construction Industries with impacts of 3.7 MW and 3.0 MW, respectively. These two groups contribute to 87% of total load reduction (See Figure 4-3). Two of the industries, Schools and Institutional/Government, show negative impacts.

In Figure 4-3, we present the share of the total enrollment, impacts, and reference load by industry.

Table 4-5 PG&E Large: Average Event-Hour Impacts by Industry on a Typical Event Day[32]

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	261	46.7	3.0	6.52%	96.0
2. Manufacturing	146	53.0	3.7	7.00%	96.6
3. Wholesale, Transport, Other Utilities	180	34.6	1.2	3.46%	96.1
4. Retail stores	42	9.9	<0.1	-0.14%	98.1
5. Offices, Hotels, Finance, Services	134	42.0	0.2	0.36%	96.7
6. Schools	39	5.9	-0.2	-2.74%	98.7
7. Institutional/Government	56	[redacted]	[redacted]	[redacted]	95.2
8. Other or unknown	8	[redacted]	[redacted]	[redacted]	92.3

Figure 4-3 PG&E Large: Contributions by Industry on a Typical Event Day



[32] Note that the total share of impacts is based upon the absolute value of the impacts to properly normalize for both positive and negative impacts.

PG&E Large: by LCA

Next, we look at load impacts for PG&E large customers by LCA. Table 4-6 summarizes aggregate event-hour results for the typical event day for PG&E's eight LCAs. The tables include the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Again, insignificant estimates are highlighted in red font.

As one might expect, enrollments are concentrated in the Greater Bay and Fresno Areas, with 53% of all participants coming from the two areas combined. The largest estimated load impacts, 2.6 MW, come from the Greater Fresno Area, with impacts in other areas being substantially lower. Impacts in the Greater Bay Area are likely to be low relative to their overall participation due to the milder weather experienced there compared to the Greater Fresno Area which tends to experience more extreme summer heat. This is also demonstrated by the greater average event temperatures for the Greater Fresno and Kern Areas (See Table 4-6).

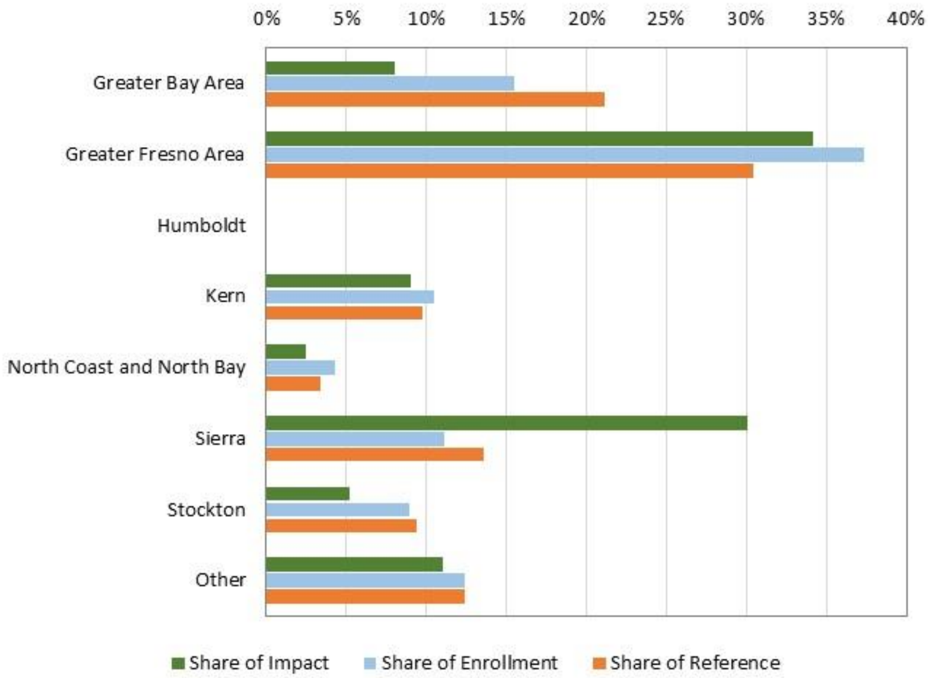
In Figure 4-4, we present the share of the total enrollment, impacts, and reference load by LCA.[33]

Table 4-6 PG&E Large: Average Event-Hour Impacts by LCA on a Typical Event Day

LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Greater Bay Area	134	46.5	0.6	1.33%	86.5
Greater Fresno Area	323	66.9	2.6	3.93%	101.2
Humboldt	-	-	-	-	-
Kern	91	21.5	0.7	3.23%	100.9
North Coast and North Bay	37	7.5	0.2	2.55%	96.8
Sierra	96	29.9	2.3	7.72%	97.0
Stockton	77	20.7	0.4	1.94%	98.3
Other	107	27.2	0.8	3.11%	93.7

[33] Note that the total share of impacts is based upon the absolute value of the impacts to properly normalize for both positive and negative impacts.

Figure 4-4 PG&E Large: Contributions by LCA on a Typical Event Day



Results for Medium Customers (20 ≤ x < 200 kW)

This section summarizes results for all medium PG&E program participants, defined as customers with maximum demand equal to or greater than 20 kW but less than 200 kW. The results are presented in the same format as the previous section. Again, results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent sub-sections.

Figure 4-5 presents the average event-hour ex-post load impacts for each individual event day for all of PG&E's medium PDP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

These results indicate that medium PDP participants had statistically significant changes in usage on all events except for the weekend event, September 6th. The medium PDP participants had an average impact of 4.6 MW. Table 4-7 shows enrollment increased slightly over time from 13,878 participants during the first event to 13,926 participants on the last event.

Figure 4-5 PG&E Medium all Participants: Average Event-Hour Impacts by Event

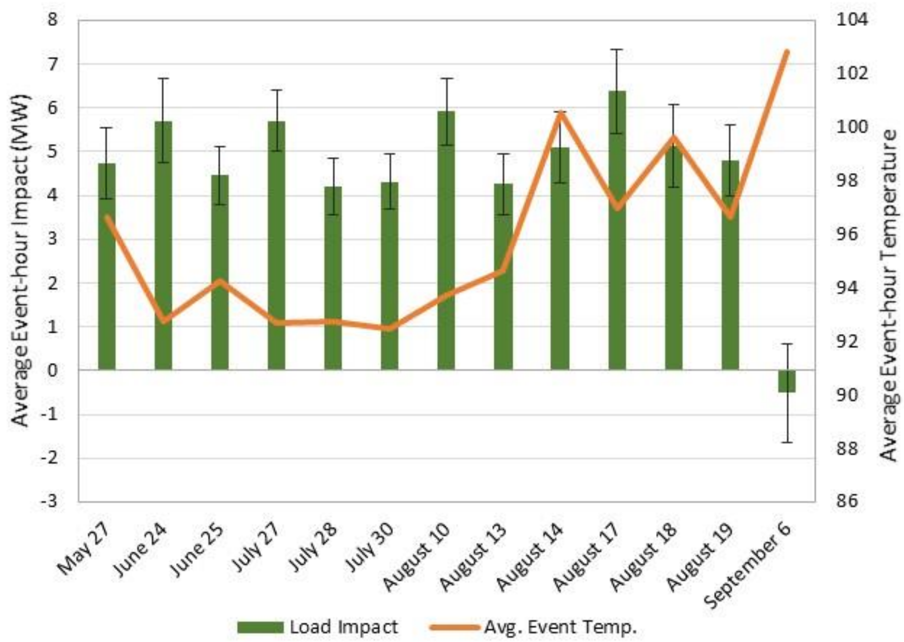
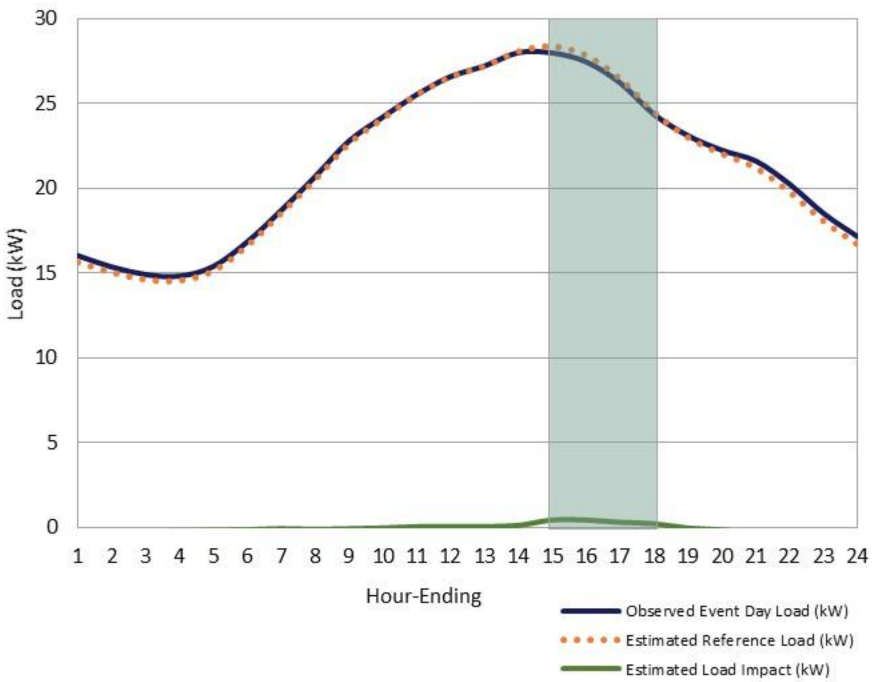


Table 4-7 PG&E Medium all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	13,878	372.3	4.7	26.8	0.3	1.27%	96.7
June 24	13,904	378.4	5.7	27.2	0.4	1.51%	92.7
June 25	13,905	381.3	4.5	27.4	0.3	1.17%	94.3
July 27	13,914	362.8	5.7	26.1	0.4	1.57%	92.7
July 28	13,914	366.3	4.2	26.3	0.3	1.15%	92.7
July 30	13,914	363.8	4.3	26.1	0.3	1.19%	92.5
August 10	13,919	384.7	5.9	27.6	0.4	1.54%	93.7
August 13	13,921	380.9	4.3	27.4	0.3	1.12%	94.6
August 14	13,921	412.4	5.1	29.6	0.4	1.24%	100.6
August 17	13,922	421.8	6.4	30.3	0.5	1.51%	97.0
August 18	13,922	429.4	5.1	30.8	0.4	1.20%	99.7
August 19	13,922	397.2	4.8	28.5	0.3	1.20%	96.7
September 6	13,926	322.4	-0.5	23.1	<0.1	-0.16%	102.8
Typical Event Day	**13,914**	**382.6**	**4.6**	**27.5**	**0.3**	**1.21%**	**95.9**

Figure 4-6 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. The impacts in this case are extremely flat and the observed and reference loads show no visible differences on event days during the event window.

Figure 4-6 PG&E Medium all Participants: Hourly Typical Event Day Load Impacts



PG&E Medium: by Industry

Next, we look at load impacts for PG&E's medium customers by industry group. Table 4-8 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Enrollments are concentrated in the Offices, Hotels, Finance & Services. This group represents 35% of the total enrolled customers. Three of the industries, show negative impacts, however, they are very small at the per-customer level and are most likely a result of modeling noise and omitted variable bias.

Table 4-8 PG&E Medium: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	596	14.7	1.5	9.97%	98.0
2. Manufacturing	934	20.5	-0.1	-0.54%	95.5
3. Wholesale, Transport, other utilities	1,916	42.3	2.4	5.59%	95.4
4. Retail stores	2,060	70.5	1.1	1.56%	95.9
5. Offices, Hotels, Finance, Services	4,927	152.9	-1.9	-1.27%	94.2
6. Schools	803	30.2	1.1	3.70%	98.0
7. Institutional/Government	2,363	45.8	0.7	1.61%	95.7
8. Other or unknown	316	5.7	-0.1	-1.76%	94.4

PG&E Medium: by LCA

Finally, we examine load impacts for PG&E's medium customers by LCA. Table 4-9 summarizes aggregate event-hour results for the typical event day for PG&E's eight LCAs. The tables include the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load and the average event temperature. The largest number of enrollments are concentrated to the Greater Fresno, Sierra, and Other Areas with about 60% of the participants coming from those three areas.

Table 4-9 PG&E Medium: Average Event-Hour Impacts by LCA on a Typical Event Day

LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Greater Bay Area	1,654	48.3	0.4	0.87%	91.3
Greater Fresno Area	3,852	104.4	1.6	1.53%	101.0
Humboldt	17	0.3	0.0	1.86%	75.5
Kern	1,506	41.8	0.5	1.27%	100.8
North Coast and North Bay	953	26.8	0.2	0.86%	95.5
Sierra	2,008	56.2	0.7	1.32%	97.8
Stockton	1,388	38.9	0.4	1.05%	98.4
Other	2,536	66.0	0.7	1.05%	94.5

Results for Small Customers (< 20 kW)

This section summarizes results for all small PG&E program participants, defined as customers with maximum demand less than 20 kW. The results are presented in the same format as the previous section. Again, results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent sub-sections.

Figure 4-7 presents the average event-hour ex post load impacts for each individual event day for all of PG&E's small PDP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

The per-customer impacts for these participants (shown in Figure 4-7 and associated Table 4-10) range from 1.42% to 2.47%. In addition, the load impacts are statistically significant on events.

Table 4-10 shows enrollment grew slightly over time with 86,808 participants during the first event to 86,863 participants on the last event.

Figure 4-7 PG&E Small all Participants: Average Event-Hour Impacts by Event

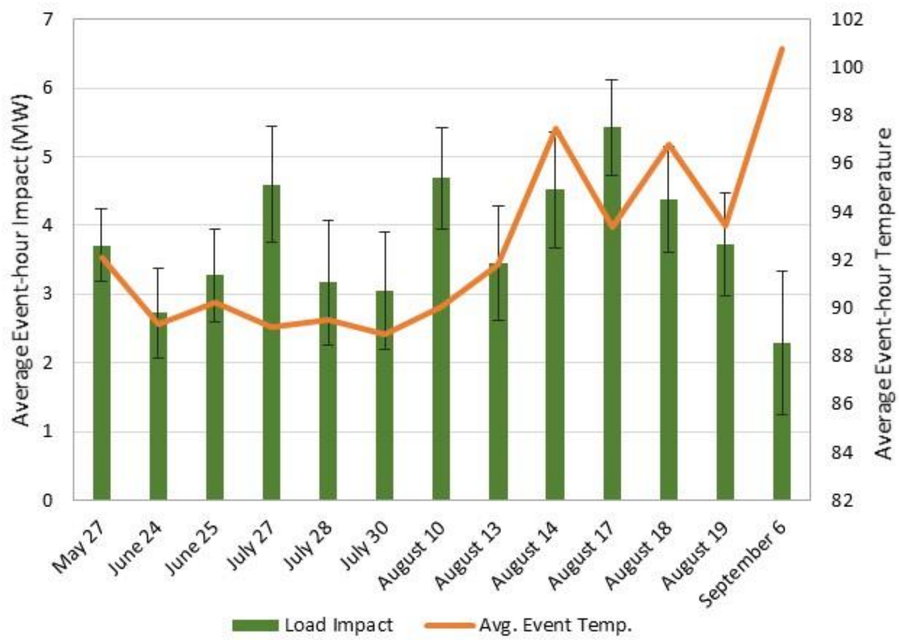
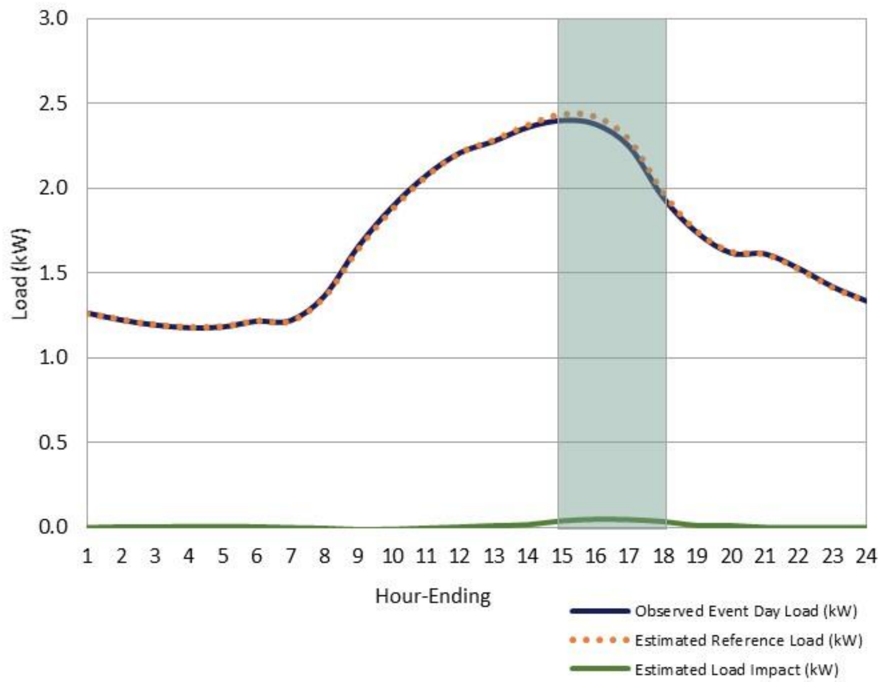


Table 4-10 PG&E Small Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	86,808	199.4	3.7	2.3	<0.1	1.86%	92.1
June 24	86,841	208.3	2.7	2.4	<0.1	1.31%	89.3
June 25	86,843	211.5	3.3	2.4	<0.1	1.55%	90.2
July 27	86,851	195.0	4.6	2.2	0.1	2.36%	89.2
July 28	86,852	199.4	3.2	2.3	<0.1	1.59%	89.5
July 30	86,854	198.1	3.0	2.3	<0.1	1.54%	88.9
August 10	86,856	203.7	4.7	2.3	0.1	2.30%	90.1
August 13	86,856	199.9	3.4	2.3	<0.1	1.72%	91.8
August 14	86,856	217.6	4.5	2.5	0.1	2.08%	97.4
August 17	86,857	219.5	5.4	2.5	0.1	2.47%	93.4
August 18	86,858	229.8	4.4	2.6	0.1	1.91%	96.8
August 19	86,859	211.2	3.7	2.4	<0.1	1.77%	93.4
September 6	86,863	161.1	2.3	1.9	<0.1	1.42%	100.8
Typical Event Day	**86,850**	**204.2**	**3.8**	**2.4**	**<0.1**	**1.85%**	**92.5**

Figure 4-8 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. The impacts in this case are extremely flat and the observed and reference loads show no visible differences on event days during the event window.

Figure 4-8 PG&E Small all Participants: Hourly Typical Event Day Load Impacts



PG&E Small: by Industry

Next, we look at load impacts for PG&E's small customers by industry group. Table 4-11 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Enrollments are concentrated in the Offices, Hotels, Finance & Services, and Institutional/Government groups. These two groups represent 55% of the total enrolled customers. The Wholesale, Transport, Other Utilities group shows a negative impact, however, it is very small at the per-customer level and is statistically insignificant.

Table 4-11 PG&E Small: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	5,810	10.2	0.2	1.48%	95.6
2. Manufacturing	3,475	7.0	<0.1	-0.13%	94.9
3. Wholesale, Transport, other utilities	14,998	18.8	-0.1	-0.66%	86.4
4. Retail stores	7,481	31.5	0.7	2.08%	88.7
5. Offices, Hotels, Finance, Services	29,587	91.0	2.1	2.35%	92.6
6. Schools	1,415	4.2	0.1	2.01%	95.5
7. Institutional/Government	18,012	31.6	0.7	2.14%	93.3
8. Other or unknown	6,073	9.8	0.2	1.96%	94.4

PG&E Small: by LCA

Finally, we examine the load impacts for PG&E's small customers by LCA. Table 4-12 summarizes aggregate event-hour results for the typical event day for PG&E's eight LCAs. The table includes the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load and the average event temperature. Enrollments are concentrated to the Greater Fresno, Sierra and Other Areas with about 63% of the participants coming from those areas.

Table 4-12 PG&E Small: Average Event-Hour Impacts by LCA on a Typical Event Day

LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Greater Bay Area	9,257	23.8	0.3	1.31%	89.5
Greater Fresno Area	22,047	55.2	1.1	2.06%	87.7
Humboldt	239	0.3	<0.1	0.66%	78.9
Kern	6,754	18.5	0.3	1.74%	100.1
North Coast and North Bay	7,715	16.2	0.3	1.96%	94.9
Sierra	14,379	31.1	0.6	2.00%	97.2
Stockton	8,514	19.1	0.4	1.99%	97.9
Other	17,946	40.0	0.7	1.69%	93.8

Dually Enrolled Customers

Next, we present the impacts for PG&E's dually enrolled customers. On a typical event day, a total of 100 customers were dually enrolled in either PG&E's Capacity Bidding Program (CBP) or the Base Interruptible Program (BIP). These customers demonstrate consistent positive impacts ranging from 2.2 MW to 4.4 MW (17% to 23%) and impacts across each individual day was insignificant, however the overall impact on the typical event day was significant.

Figure 4-9 presents the average event-hour ex-post load impacts for each individual event day for the dually enrolled customers. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-9 PG&E Dually Enrolled Participants: Average Event-Hour Impacts by Event

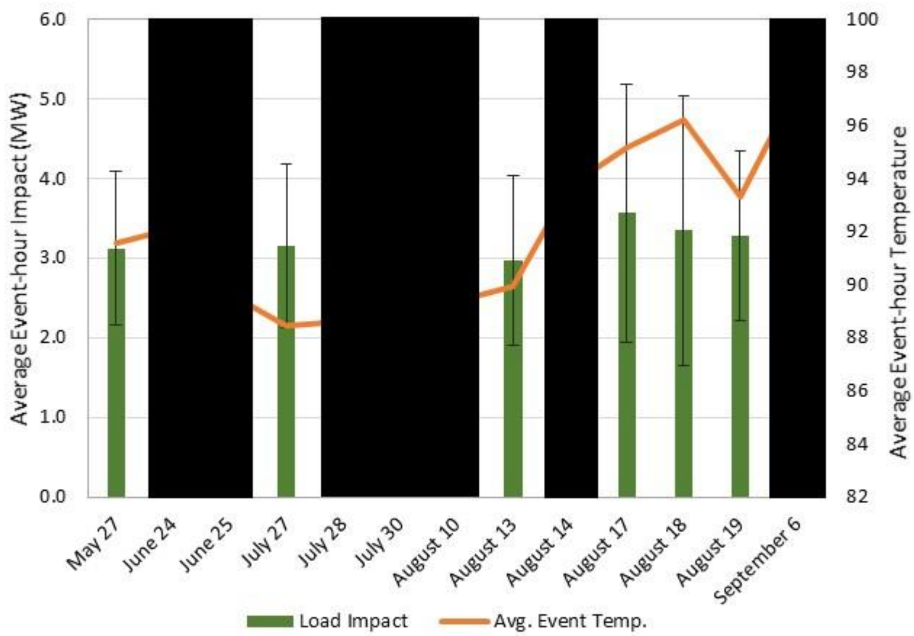


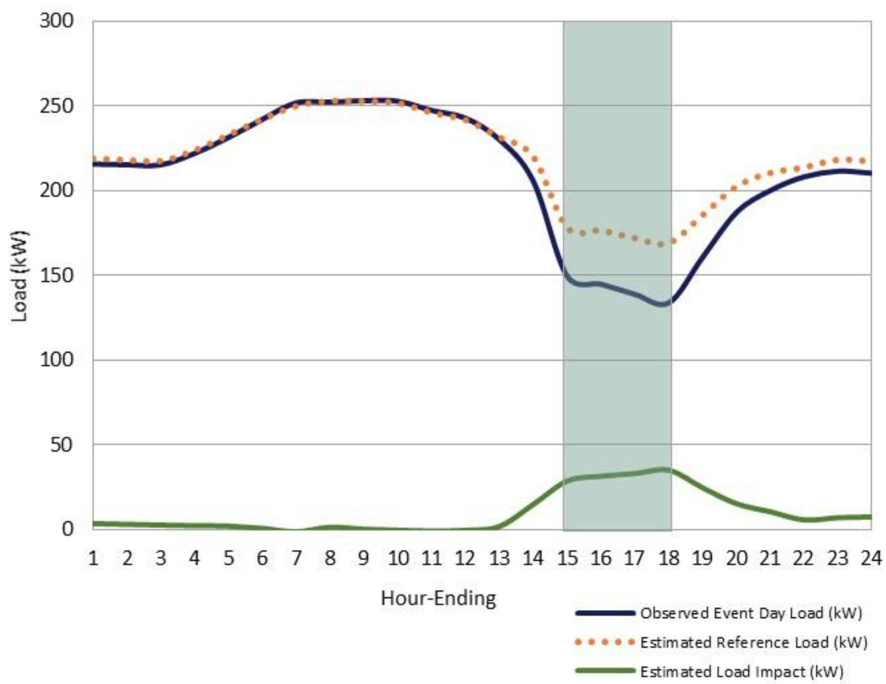
Table 4-13, presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day. Insignificant impacts are identified in red font.

Table 4-13 PG&E Dually Enrolled Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	97	17.7	3.1	182.9	32.2	17.61%	91.6
June 24	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92.1
June 25	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89.7
July 27	100	18.0	3.2	180.3	31.5	17.48%	88.4
July 28	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88.6
July 30	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88.7
August 10	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89.4
August 13	100	18.8	3.0	188.0	29.7	15.82%	90.0
August 14	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93.8
August 17	100	15.4	3.6	154.2	35.6	23.10%	95.2
August 18	100	12.4	3.3	124.2	33.5	26.94%	96.2
August 19	100	14.0	3.3	140.0	32.8	23.43%	93.3
September 6	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97.5
Typical Event Day	**100**	**16.7**	**3.2**	**167.8**	**32.1**	**19.14%**	**91.9**

Figure 4-10 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. Notice that impacts outside the event window are very small relative to the event window impacts indicating a consistent load reduction without shifting of load into non-event hours.

Figure 4-10 PG&E Dually Enrolled Participants: Hourly Typical Event Day Load Impacts



Automated Demand Response Customers

Next, we present the impacts for PG&E's Automated Demand Response (AutoDR) customers. PG&E's AutoDR customers have load reduction equipment installed at their facilities which automates their response during events. On a typical event day, a total of 5 customers were participating in the AutoDR program. The per-customer impacts are extremely small ranging from 0.2 to 0.5 kW. Six of the thirteen event days had statistically significant impacts.

Figure 4-11 presents the average event-hour ex post load impacts for each individual event day for all of PG&E's AutoDR participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-11 PG&E AutoDR Participants: Average Event-Hour Impacts by Event

[redacted]

Table 4-14 presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day.

Table 4-14 PG&E AutoDR Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
May 27	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69.0
June 24	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67.8
June 25	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67.5
July 27	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66.8
July 28	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66.9
July 30	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67.9
August 10	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67.8
August 13	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61.8
August 14	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69.3
August 17	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70.2
August 18	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69.3
August 19	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66.9
September 6	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68.7
Typical Event Day	**5**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**67.7**

Figure 4-12 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day.

Figure 4-12 PG&E AutoDR Participants: Hourly Typical Event Day Load Impacts

Notified vs. Non-Notified Customers

PDP is a default rate for PG&E's non-residential customers and as such, participants are notified of an event if their contact information is provided to PG&E. However, customers that do not receive notification probably do not know that an event is occurring and would therefore find it difficult to respond. Customers can receive day ahead notifications for events by setting up their account to receive alerts either by email, or by text message. PG&E discontinued their in-season support in 2019, which provided additional information including post event feedback to participants.

Table 4-13 and Table 4-16 present the percentage of service accounts receiving notification by size group and the per-customer impacts by size group, and notification, on a typical event day, respectively.

In looking at Table 4-13, we note that across all customer groups 84% received notification, a decrease from 92% last year. A similar percentage (84%) of the load impacts come from customers that are receiving notification. When we compare the difference in per-customer impacts by size, in Table 4-16, we can see that notification has no impact at a per-customer level. The small and medium customers show negligible reductions regardless of whether they are notified of events and large customers who are not notified actually have larger per-customer reductions. This suggests that increasing notifications will not improve the impacts.

Table 4-15 Percent of Service Accounts Receiving Notification, by Size Group: Typical Event Day

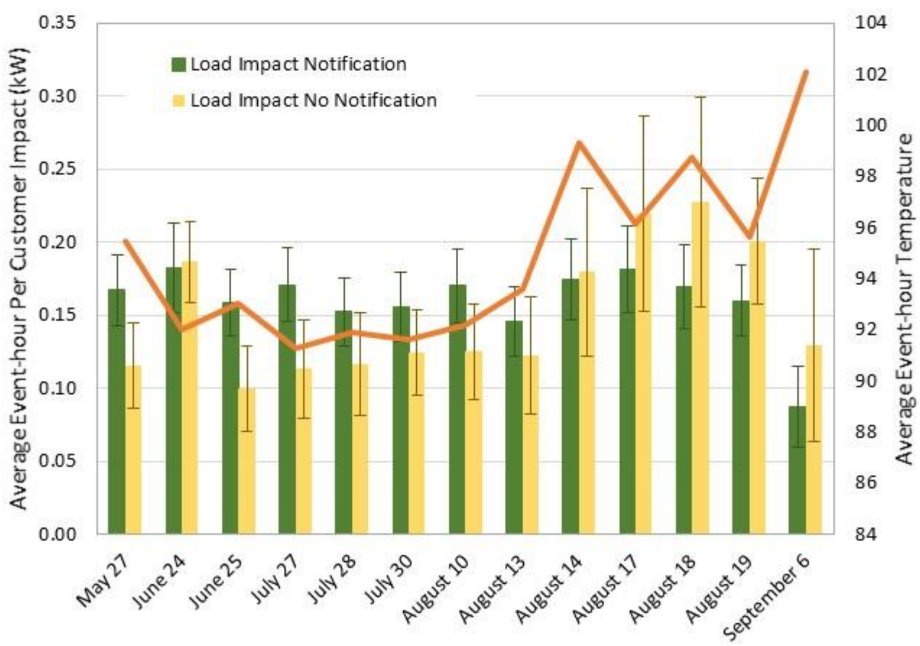
Size Group	PG&E % Notified
Large (≥ 200 kW)	87%
Medium (20 kW ≤ x < 200 kW)	87%
Small (< 20 kW)	84%
Total	**84%**

Table 4-16 Per-Customer Impacts by Size Group and Notification: Typical Event Day

Notification	Size group	# Customers	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)
No	Large	111	247.5	11.9	1.3
	Medium	1,849	26.7	0.4	0.8
	Small	14,114	2.1	0.0	0.4
	All	**16,074**	**6.6**	**0.2**	**2.5**
Yes	Large	754	255.6	8.4	6.4
	Medium	12,065	27.6	0.3	3.8
	Small	72,736	2.4	0.0	3.4
	All	**85,556**	**8.2**	**0.2**	**13.6**

In Figure 4-13 below we compare the average event hour impacts on each event day, by notification, for all customers in PY2020.

Figure 4-13 Comparison Average Event-Hour of Impacts by Level of Communication



SCE

This section presents the ex-post load impact analysis for SCE. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the typical event day as well as for each individual event. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

Table 4-17 summarizes the overall, program level, event-hour impacts on each event, including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature.

Table 4-17 SCE All Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	245,762	1,236.9	7.3	5.0	<0.1	0.59%	81.4
July 10	245,588	1,287.5	8.5	5.2	<0.1	0.66%	83.2
July 13	245,394	1,291.8	10.4	5.3	<0.1	0.80%	87.4
July 15	245,275	1,209.2	8.9	4.9	<0.1	0.73%	79.7
July 20	244,897	1,209.8	9.4	4.9	<0.1	0.78%	81.5
August 3	243,902	1,246.6	14.3	5.1	0.1	1.15%	82.9
August 4	243,847	1,214.4	15.1	5.0	0.1	1.25%	82.4
August 12	243,092	1,263.8	12.8	5.2	0.1	1.02%	83.0
August 13	243,008	1,292.9	15.4	5.3	0.1	1.19%	85.9
August 17	242,811	1,364.9	13.6	5.6	0.1	1.00%	88.3
August 18	242,808	1,383.3	17.6	5.7	0.1	1.27%	89.8
August 19	242,709	1,390.5	16.7	5.7	0.1	1.20%	89.4
Typical Event Day	**244,091**	**1,282.6**	**12.5**	**5.3**	**0.1**	**0.98%**	**84.6**

Comparison of Ex-Post Impacts

In Table 4-18 and Table 4-19 below we present the comparison of current ex-post impacts to previous ex-post impacts, and current ex-post impacts to prior ex-ante impacts. These comparisons give the reader with a sense of how the program has performed over time, and how the program has performed relative to the most recent forecast.

Table 4-18 SCE Non-Residential CPP: Previous and Current Ex-Post, Typical Event Day

Program Year	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
2019	Large	2,201	426.9	7.0	194.0	3.2	1.65%	88.7
	Medium	34,963	861.8	-1.4	24.6	<0.1	-0.16%	88.0
	Small	235,219	340.4	-0.7	1.4	<0.1	-0.22%	87.1
	All	**272,383**	**1,629.1**	**4.9**	**6.0**	**<0.1**	**0.30%**	**87.9**
2020	Large	1,895	330.0	8.3	174.1	4.4	2.53%	87.2
	Medium	29,581	668.6	3.4	22.6	0.1	0.51%	84.4
	Small	212,615	284.1	0.8	1.3	<0.1	0.28%	81.2
	All	**244,091**	**1,282.6**	**12.5**	**5.3**	**0.1**	**0.98%**	**84.6**

Table 4-18 above, presents the ex-post from PY2019 compared to PY2020. SCE's non-residential CPP program has decreased in participants, but increased substantially in total impacts, and percent impacts compared to PY2019. In addition, it is important to note that SCE's large default population in the small and medium groups also entered their second year of participation on CPP. After twelve months, these participants lost their bill protection guarantee and were exposed to the full monetary impacts of the rate. This may have encouraged customers to increase their response to the rate.

Across all three IOUs the weather was more extreme in PY2020. While the overall average temperatures were similar across the whole summer relative to PY2019, a significant heatwave hit the state in late August and early September bringing record temperatures. For weather sensitive customers the increased heat also resulted in increased impacts. Additionally, having more extreme days in our underlying data allowed for more accurate modeling of weather relationships which may also have contributed to the increase impacts.

It is also possible that COVID-19 conditions may have affected how customers responded to CPP events. Given the depressed economic conditions across the country, it is possible that participants had additional incentive to save energy (and money) over the summer of 2020. Also reduced capacities at many retail and restaurant locations may have facilitated additional response.

In Table 4-19 below, we present the PY2020 ex-post impacts compared to prior ex-ante impacts. Overall, total MW impacts are larger in PY2020 relative to PY2019 based on the increased responsiveness of small and medium customers.

Table 4-19 SCE Non-Residential CPP: Previous Ex-Ante (SCE 1-in-2, Typical Event Day, 2020) and Current Ex-Post (Typical Event Day)

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante	Large	2,525	498.2	8.0	197.3	3.2	1.60%	88.2
	Medium	30,298	750.1	0.0	24.8	0.0	0.00%	87.9
	Small	219,658	328.9	0.0	1.5	0.0	0.00%	87.1
	All	**252,481**	**1,577.2**	**8.0**	**6.2**	**<0.1**	**0.51%**	**87.2**
Current Ex-Post	Large	1,895	330.0	8.3	174.1	4.4	2.53%	87.2
	Medium	29,581	668.6	3.4	22.6	0.1	0.51%	84.4
	Small	212,615	284.1	0.8	1.3	<0.1	0.28%	81.2
	All	**244,091**	**1,282.6**	**12.5**	**5.3**	**0.1**	**0.98%**	**84.6**

Results for Large Customers (≥ 200 kW)

This section summarizes results for all large SCE program participants, defined as customers with maximum demand equal to or greater than 200 kW. The results are presented as follows:

- Average event-hour impacts for each individual event day
- Hourly load impacts for a typical event day
- Average event-hour impacts on a typical event day by industry group and LCA

Results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent subsections.

Figure 4-14 presents the average event-hour ex post load impacts for each individual event day for all of SCE's large CPP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

These results indicate that large customers had statistically significant load reductions on each of the twelve event days, ranging from 4.1 MW to 12.3 MW. The load impact averaged 8.3 MW, with five event days having a load impact lower than 8 MW.

Table 4-20 summarizes the event-hour impacts on each event, including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Load impacts as a percent of the reference load were 2.53% on average across the twelve events. Enrollment dropped slightly over time by 37 participants, or 2%.

Figure 4-14 SCE Large all Participants: Average Event-Hour Impacts by Event

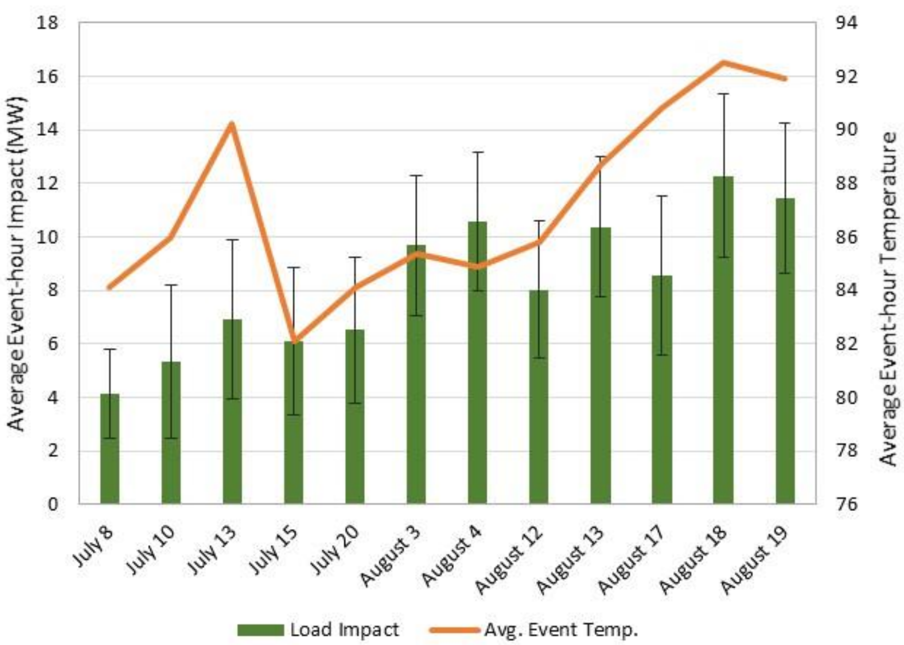


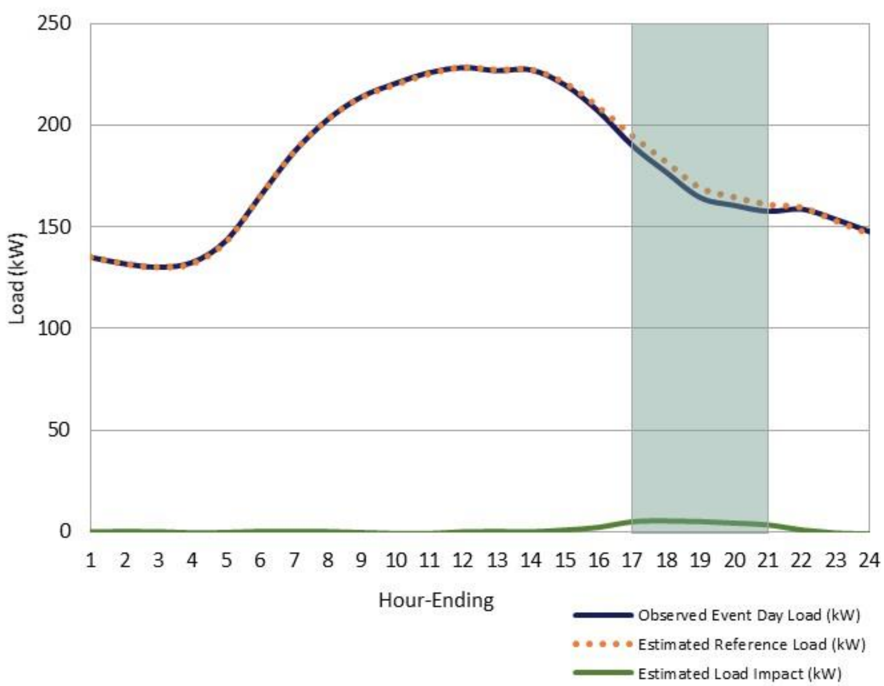
Table 4-20 SCE Large all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	1,918	322.1	4.1	168.0	2.2	1.29%	84.1
July 10	1,912	321.7	5.3	168.2	2.8	1.66%	86.0
July 13	1,911	333.2	6.9	174.3	3.6	2.08%	90.2

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 15	1,908	317.5	6.1	166.4	3.2	1.92%	82.1
July 20	1,905	319.9	6.5	167.9	3.4	2.04%	84.1
August 3	1,890	325.4	9.7	172.2	5.1	2.98%	85.4
August 4	1,888	322.1	10.6	170.6	5.6	3.28%	84.9
August 12	1,884	326.0	8.0	173.0	4.3	2.46%	85.8
August 13	1,884	333.3	10.4	176.9	5.5	3.11%	88.7
August 17	1,882	341.9	8.6	181.6	4.6	2.51%	90.8
August 18	1,881	346.0	12.3	184.0	6.5	3.55%	92.5
August 19	1,881	350.6	11.5	186.4	6.1	3.27%	91.9
Typical Event Day	**1,895**	**330.0**	**8.3**	**174.1**	**4.4**	**2.53%**	**87.2**

Figure 4-15 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. Hourly load impacts do not show evidence of pre-cooling or post-event snapback. This is typical of large participants that tend to be less weather sensitive and participate using a mix of end-uses rather than cooling dominate SMB or residential customers.

Figure 4-15 SCE Large all Participants: Hourly Typical Event Day Load Impacts



SCE Large: by Industry

Next, we look at load impacts for SCE large customers by industry group. Table 4-21 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Insignificant impacts are highlighted in dark red font.

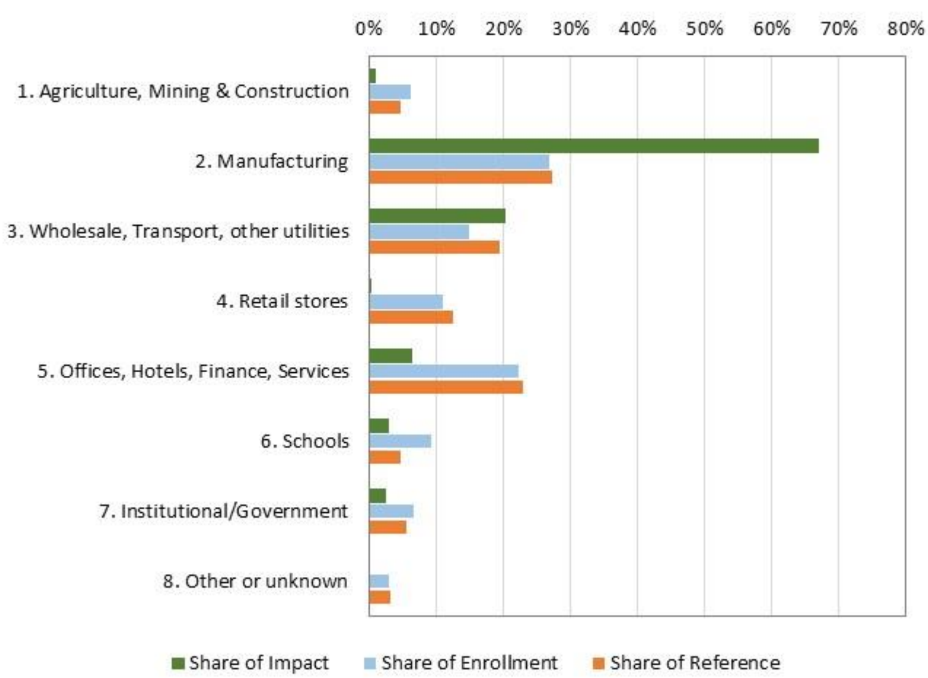
Enrollments are concentrated in the Manufacturing and Offices, Hotels, Finance and Services groups. These two groups represent 49% of the total enrolled customers. The largest estimated load impact is from Manufacturing with an impact of 5.6 MW.

In Figure 4-16, we present the share of the total enrollment, impacts, and reference load by industry.[34]

Table 4-21 SCE Large: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	119	15.2	0.1	0.51%	93.4
2. Manufacturing	508	89.9	5.6	6.23%	87.9
3. Wholesale, Transport, other utilities	281	63.9	1.7	2.65%	89.4
4. Retail stores	208	41.3	<0.1	-0.06%	82.5
5. Offices, Hotels, Finance, Services	424	75.9	0.5	0.71%	81.1
6. Schools	173	15.4	0.2	1.58%	85.1
7. Institutional/Government	124	18.2	0.2	1.11%	89.0
8. Other or unknown	57	10.4	<0.1	0.10%	87.4

Figure 4-16 SCE Large: Contributions by Industry on a Typical Event Day



[34] Note that the total share of impacts is based upon the absolute value of the impacts to properly normalize for both positive and negative impacts.

SCE Large: by LCA

Next, we look at load impacts for SCE large customers by LCA. Table 4-22 summarizes aggregate event-hour results for the typical event day for the three SCE LCAs. The tables include the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load and the average event temperature. Insignificant estimates are highlighted in red font.

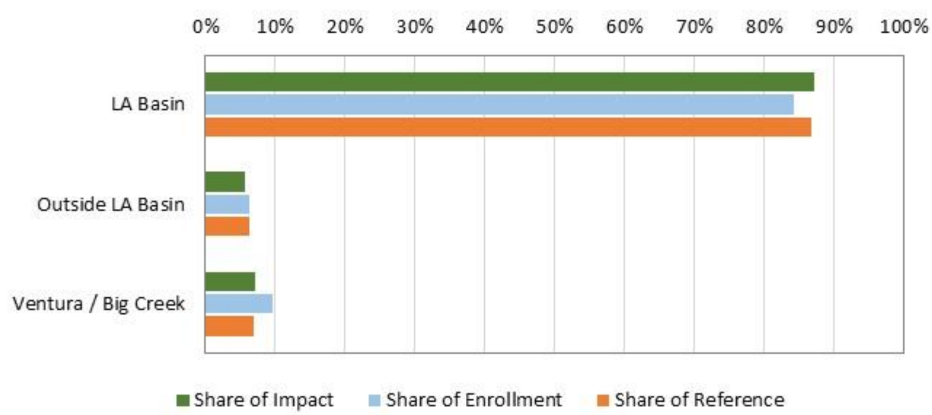
As one might expect, enrollments are concentrated in the LA Basin comprising about 84% of the participants. The largest estimated load impact, 7.3 MW, comes from the LA Basin, with impacts in other areas being substantially lower. However, each LCA experienced about similar percent impacts (~2.5%).

In Figure 4-17, we present the share of the total enrollment, impacts, and reference load by LCA.[35]

Table 4-22 SCE Large: Average Event-Hour Impacts by LCA on a Typical Event Day

LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
LA Basin	1,596	286.3	7.3	2.54%	85.2
Outside LA Basin	118	20.6	0.5	2.34%	90.6
Ventura / Big Creek	181	23.1	0.6	2.56%	88.4

Figure 4-17 SCE Large: Contributions by LCA on a Typical Event Day



Results for Medium Customers (20 < x ≤ 200 kW)

This section summarizes results for all medium SCE program participants, defined as customers with maximum demand greater than 20 kW but less than or equal to 200 kW. The results are presented in the same format as the previous section. Again, results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent sub-sections.

Figure 4-18 presents the average event-hour ex post load impacts for each individual event day for all of SCE's medium CPP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

[35] Note that the total share of impacts is based upon the absolute value of the impacts in order to properly normalize for both positive and negative impacts when they are present.

These results indicate that medium CPP participants had statistically significant load increases on all twelve event days (ranging from 2.5 MW to 4.5 MW). Furthermore, the point estimates at the per-customer level are very close to zero (0.1 kW).

Figure 4-18 SCE Medium all Participants: Average Event-Hour Impacts by Event

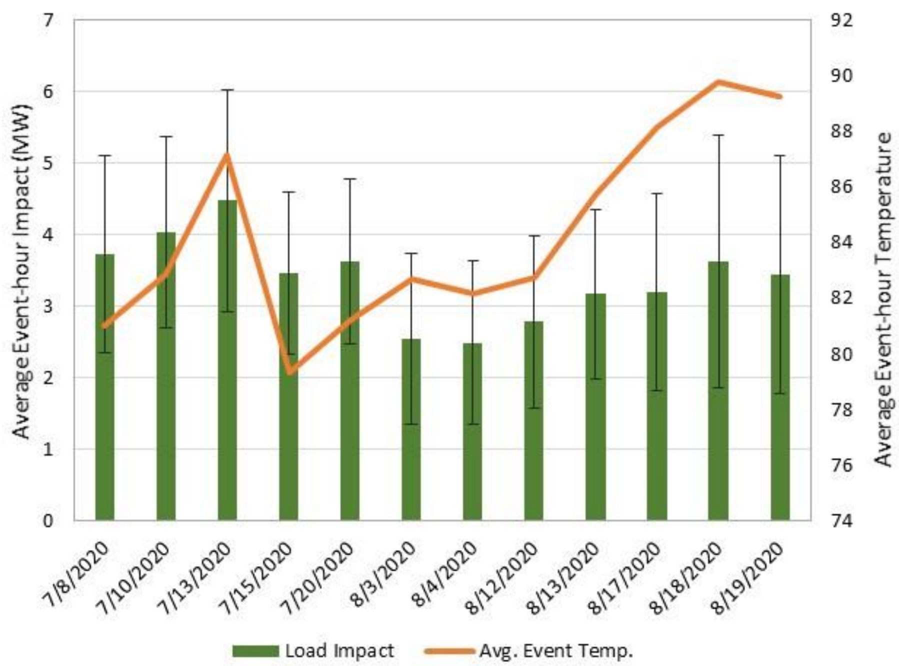


Table 4-23 summarizes the event-hour impacts on each event, including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Insignificant point estimates appear in red font.

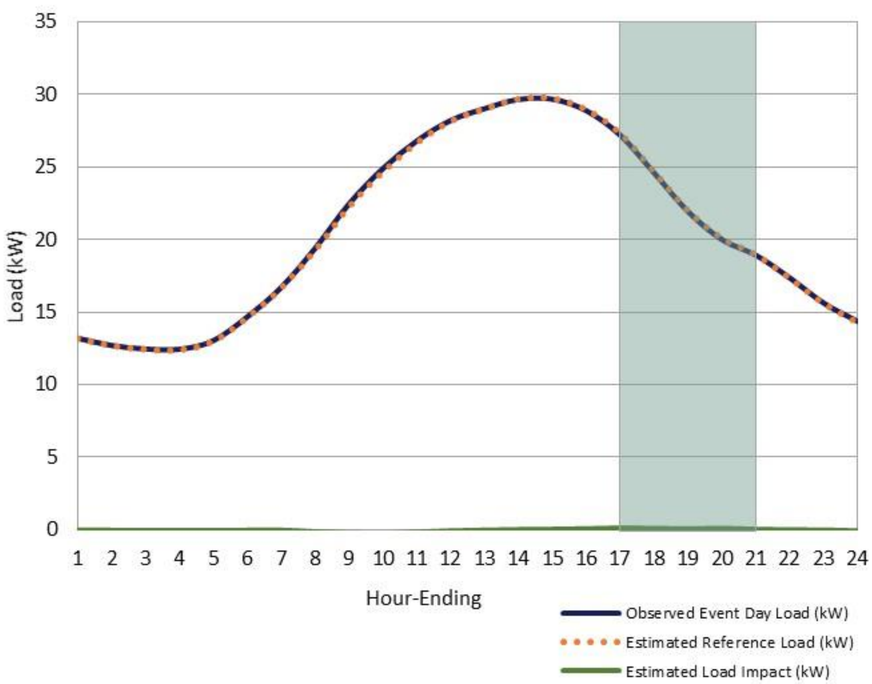
Table 4-23 SCE Medium all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	30,009	643.9	3.7	21.5	0.1	0.58%	81.0
July 10	29,941	679.5	4.0	22.7	0.1	0.59%	82.9
July 13	29,895	671.2	4.5	22.5	0.1	0.67%	87.2
July 15	29,864	629.8	3.5	21.1	0.1	0.55%	79.4
July 20	29,778	630.1	3.6	21.2	0.1	0.58%	81.2
August 3	29,524	647.6	2.6	21.9	0.1	0.39%	82.7
August 4	29,519	626.6	2.5	21.2	0.1	0.40%	82.2
August 12	29,373	656.4	2.8	22.3	0.1	0.42%	82.8
August 13	29,351	672.4	3.2	22.9	0.1	0.47%	85.8

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	29,246	715.8	3.2	24.5	0.1	0.45%	88.2
August 18	29,243	724.0	3.6	24.8	0.1	0.50%	89.8
August 19	29,231	725.6	3.4	24.8	0.1	0.47%	89.3
Typical Event Day	**29,581**	**668.6**	**3.4**	**22.6**	**0.1**	**0.51%**	**84.4**

Figure 4-19 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Note that there is no visible difference between the actual observed load and the reference load.

Figure 4-19 SCE Medium all Participants: Hourly Typical Event Day Load Impacts



SCE Medium: by Industry

Next, we look at load impacts for SCE's medium customers by industry group. Table 4-24 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Insignificant estimates are highlighted in red font. Enrollments are concentrated in the Offices, Hotels, Finance & Services representing 47% of the total enrolled customers.

Table 4-24 SCE Medium: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	1,022	17.1	0.1	0.52%	88.6
2. Manufacturing	3,009	60.9	0.2	0.34%	86.7
3. Wholesale, Transport, other utilities	2,108	45.4	0.3	0.60%	88.8
4. Retail stores	5,853	153.4	0.7	0.43%	87.6
5. Offices, Hotels, Finance, Services	13,891	334.3	1.8	0.54%	64.0
6. Schools	667	11.6	0.2	1.52%	85.1
7. Institutional/Government	2,789	41.3	0.2	0.39%	87.7
8. Other or unknown	243	4.5	<0.1	-0.20%	87.4

SCE Medium: by LCA

Finally, we present the load impacts for SCE's medium customers by LCA. Table 4-25 summarizes aggregate event-hour results for the typical event day for SCE's three LCAs. The tables include the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load and the average event temperature. As one might expect, enrollments are concentrated in the LA Basin with 84% of the participants coming from that area.

Table 4-25 SCE Medium: Average Event-Hour Impacts by LCA on a Typical Event Day

LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
LA Basin	24,762	560.2	2.7	0.48%	80.5
Outside LA Basin	2,074	48.0	0.3	0.62%	85.2
Ventura / Big Creek	2,746	60.4	0.4	0.64%	89.5

Results for Small Customers (< 20 kW)

This section summarizes results for all small SCE program participants, defined as customers with maximum demand equal to less than 20 kW. The results are presented in the same format as the previous section. Again, results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent sub-sections.

Figure 4-20 presents the average event-hour ex post load impacts for each individual event day for all of SCE's small CPP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

The small CPP participants had statistically significant changes in load in seven of the twelve event days. The per-customer point estimates are extremely small, approximately 0.0037 kWh on average.

Figure 4-20 SCE Small all Participants: Average Event-Hour Impacts by Event

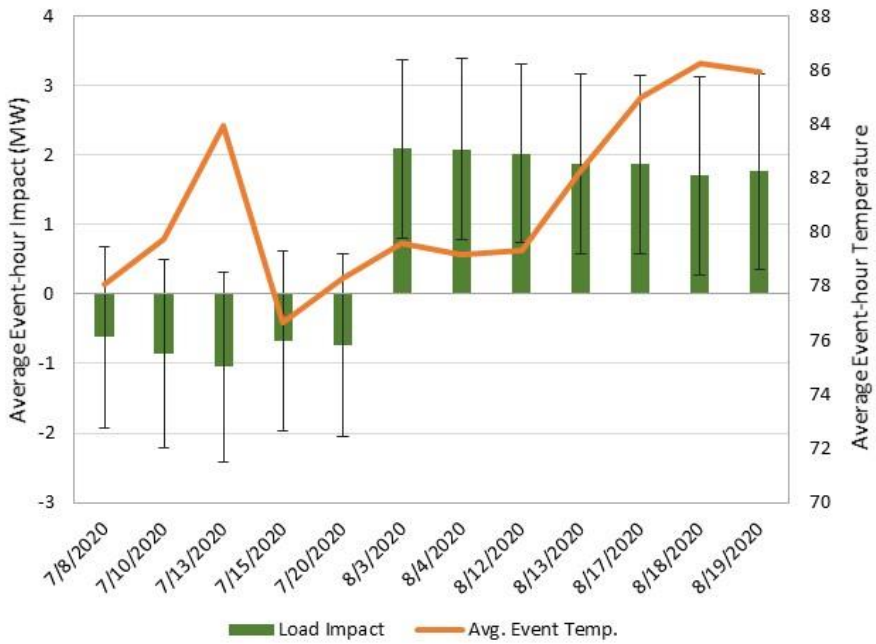


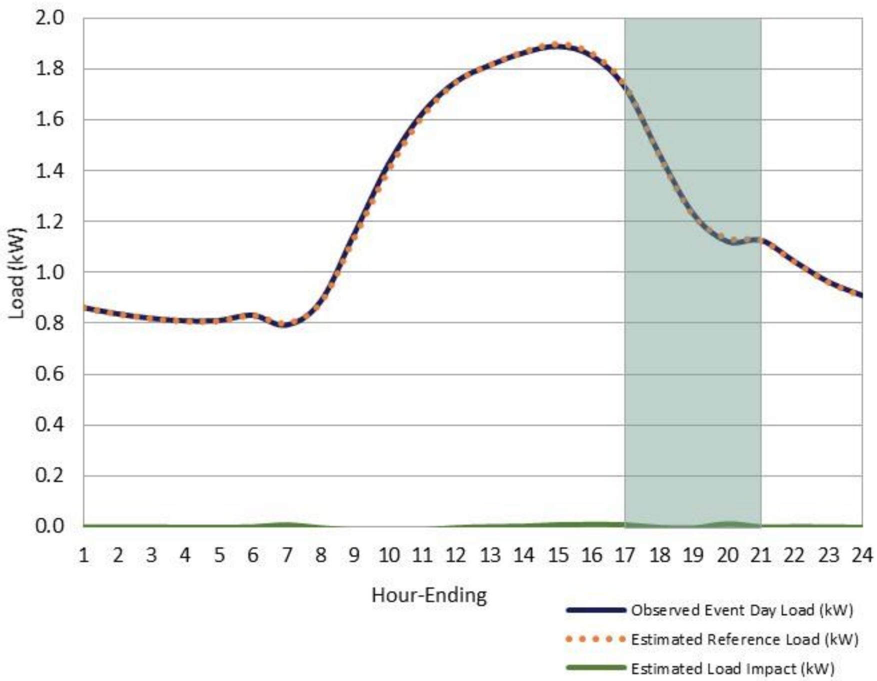
Table 4-26 summarizes the event-hour impacts on each event including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Insignificant point estimates are indicated with red font.

Table 4-26 SCE Small all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	213,835	270.9	-0.6	1.3	<0.1	-0.23%	78.1
July 10	213,735	286.3	-0.9	1.3	<0.1	-0.30%	79.8
July 13	213,588	287.4	-1.0	1.3	<0.1	-0.36%	83.9
July 15	213,503	262.0	-0.7	1.2	<0.1	-0.26%	76.7
July 20	213,214	259.8	-0.7	1.2	<0.1	-0.28%	78.3
August 3	212,488	273.5	2.1	1.3	<0.1	0.76%	79.6
August 4	212,440	265.7	2.1	1.3	<0.1	0.78%	79.2
August 12	211,835	281.4	2.0	1.3	<0.1	0.72%	79.3
August 13	211,773	287.1	1.9	1.4	<0.1	0.65%	82.3
August 17	211,683	307.3	1.9	1.5	<0.1	0.61%	85.0
August 18	211,684	313.3	1.7	1.5	<0.1	0.54%	86.2
August 19	211,597	314.3	1.8	1.5	<0.1	0.56%	85.9
Typical Event Day	**212,615**	**284.1**	**0.8**	**1.3**	**<0.1**	**0.28%**	**81.2**

Figure 4-21 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day. Again, there is an extremely small load impact during the event window.

Figure 4-21 SCE Small all Participants: Hourly Typical Event Day Load Impacts



SCE Small: by Industry

Next, we look at load impacts for SCE's small customers by industry group. Table 4-27 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Enrollments are concentrated in the Offices, Hotels, Finance and Services group. This group represents about 45% of the total enrolled customers. Wholesale, Transport, Other Utilities and Institutional/Government Groups es show negative impacts.

Table 4-27 SCE Small: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	10,055	13.6	0.2	1.19%	89.0
2. Manufacturing	7,436	9.8	0.1	0.76%	85.8
3. Wholesale, Transport, other utilities	11,774	14.3	<0.1	-0.03%	88.0
4. Retail stores	27,196	58.4	<0.1	0.08%	64.7
5. Offices, Hotels, Finance, Services	95,761	138.4	0.6	0.40%	85.1
6. Schools	2,180	3.2	<0.1	1.03%	84.5
7. Institutional/Government	30,036	30.9	-0.3	-1.01%	88.5
8. Other or unknown	28,178	15.4	0.2	1.50%	71.1

SCE Small: by LCA

Finally, we present the load impacts for SCE's small customers by LCA. Table 4-28 summarizes aggregate event-hour results for the typical event day for SCE's three LCAs. The tables include the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load and the average event temperature. As one might expect enrollments are concentrated to the LA Basin, with about 81% of the participants coming from there.

Table 4-28 SCE Small: Average Event-Hour Impacts by LCA on a Typical Event Day

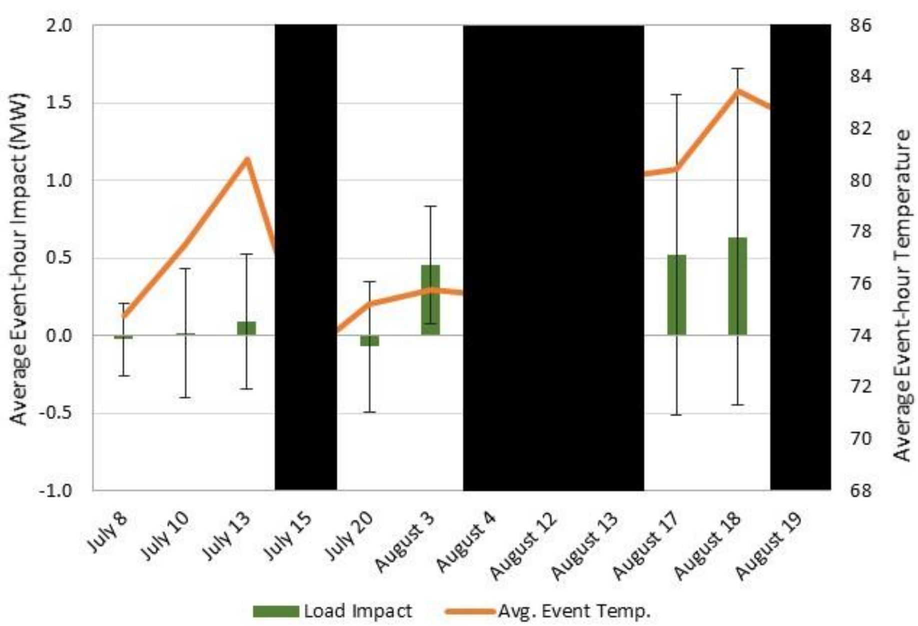
LCA	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
LA Basin	173,154	232.0	0.7	0.30%	68.9
Outside LA Basin	15,335	20.1	<0.1	0.08%	90.0
Ventura / Big Creek	24,126	32.0	0.1	0.21%	86.9

Dually Enrolled Customers

Next, we present the impacts for SCE's dually enrolled customers. On a typical event day, a total of 79 customers were dually enrolled in either SCE's Capacity Bidding Program (CBP) or Base Interruptible Program (BIP). These customers demonstrate impacts ranging from -0.1 to 0.6 MW with five of the twelve days of the impacts statistically significant.

Figure 4-22 presents the average event-hour ex-post load impacts for each individual event day for SCE's dually enrolled participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-22 SCE Dually Enrolled Participants: Average Event-Hour Impacts by Event



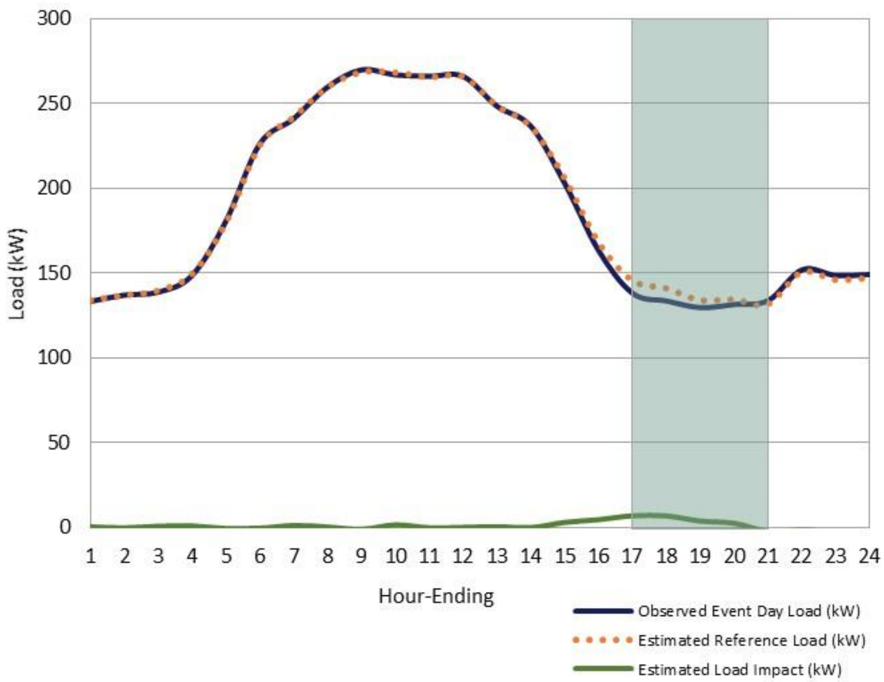
Associated Table 4-29, on the following page, presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day.

Table 4-29 SCE Dually Enrolled Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	79	10.8	<0.1	136.6	-0.3	-0.22%	74.8
July 10	79	10.2	<0.1	129.7	0.2	0.15%	77.5
July 13	79	10.5	0.1	132.5	1.1	0.85%	80.8
July 15	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73.3
July 20	79	9.6	-0.1	122.1	-0.9	-0.73%	75.2
August 3	79	11.2	0.5	142.2	5.8	4.05%	75.8
August 4	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75.6
August 12	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77.7
August 13	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80.1
August 17	79	8.2	0.5	104.1	6.6	6.34%	80.4
August 18	79	9.3	0.6	117.1	8.1	6.88%	83.4
August 19	79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82.3
Typical Event Day	**79**	**10.8**	**0.3**	**137.3**	**3.6**	**2.65%**	**78.1**

Figure 4-23 shows the average customer hourly reference loads, observed loads, and estimated load impacts on the typical event day.

Figure 4-23 SCE Dually Enrolled Participants: Hourly Typical Event Day Load Impacts



Automated Demand Response Customers

Next, we present the impacts for SCE's Automated Demand Response (AutoDR) customers. SCE's AutoDR customers have load reduction equipment installed at their facilities which automates their response during events. On a typical event day, a total of 73 customers were participating in the AutoDR program. These customers demonstrate consistent positive impacts ranging from 0.2 to 0.4 MW. Three of the twelve impacts were statistically significant.

Figure 4-24 presents the average event-hour ex-post load impacts for each individual event day for SCE's AutoDR CPP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-24 SCE AutoDR Participants: Average Event-Hour Impacts by Event

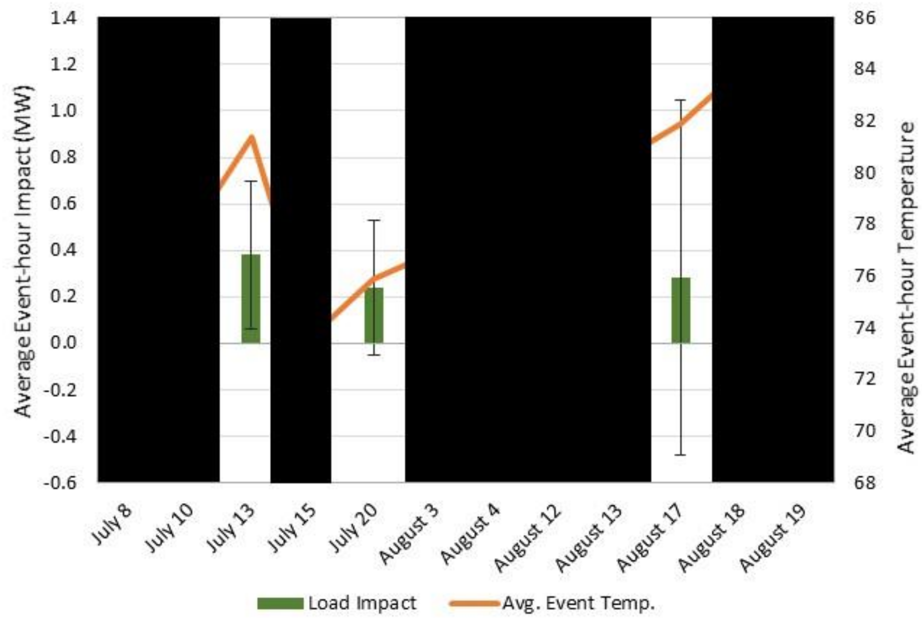


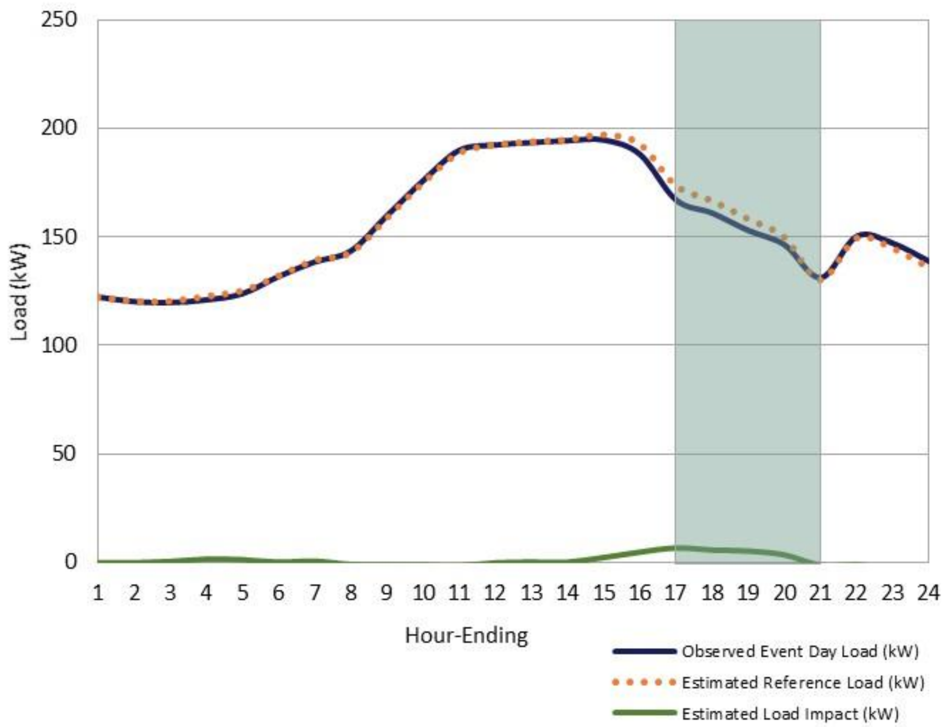
Table 4-30 presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day.

Table 4-30 SCE AutoDR Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
July 8	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75.3
July 10	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77.7
July 13	73	10.8	0.4	148.0	5.2	3.54%	81.4
July 15	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73.7
July 20	73	10.9	0.2	149.6	3.3	2.17%	75.9
August 3	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76.9
August 4	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76.6
August 12	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78.1
August 13	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80.5
August 17	73	10.1	0.3	138.3	3.8	2.78%	81.9
August 18	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84.1
August 19	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82.9
Typical Event Day	**73**	**11.3**	**0.3**	**155.6**	**3.8**	**2.45%**	**78.7**

Figure 4-25 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day.

Figure 4-25 SCE AutoDR Participants: Hourly Typical Event Day Load Impacts



Notified vs. Non-Notified Customers

Participants on SCE's CPP Rate are not required to receive event notification. Customers that do not receive notification probably do not know that an event is occurring and would therefore find it difficult to respond proactively to events. Customers can receive day-ahead notifications for events by setting up their account to receive alerts either by phone, email, or by text message.

Table 4-27 and Table 4-32 present the percentage of service accounts receiving notification by size group and the per-customer impacts by size group, and notification, on a typical event day, respectively.

In looking at Table 4-27, we note that relative to last year the percentage of service accounts receiving notification increased from 55% to 86%. And, relative to 100% last year, 63% of the load impacts come from customers are receiving notification. This shift occurred for two reasons, first there were measurable impacts in the small and medium groups in PY2020 vs, zero impacts in those groups in 2019. Second, about 140 large customers moved from receiving notification to no longer receiving notification. It is likely that those large customers are now getting their event alerts via SCE's mobile DR application instead of a text or email.

Table 4-31 Percent of Service Accounts Receiving Notification, by Size Group: Typical Event Day

Size Group	SCE % Notified
Large (≥ 200 kW)	81%
Medium (20 kW ≤ x < 200 kW)	86%
Small (< 20 kW)	86%
Total	**86%**

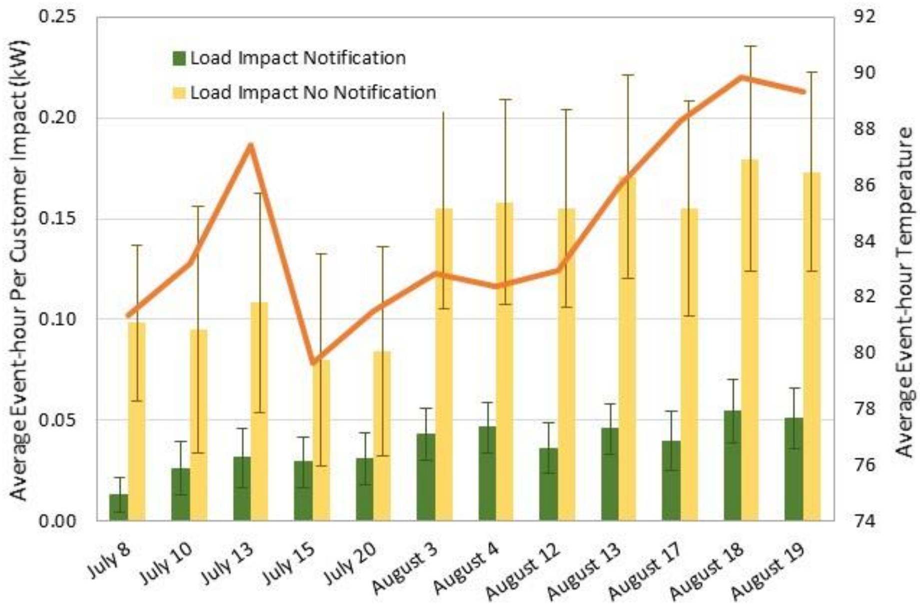
When we compare the difference in per-customer impacts by size, in Table 4-32 we can see that the key difference, at a per-customer level, comes from the large customers, where customers who were not notified had significantly more per-customer load. The small and medium customers show negligible reductions regardless of whether they are notified of events. This suggests that notifications and/or increasing notifications will not improve the impacts.

Table 4-32 Per-Customer Impacts by Size Group and Notification: Typical Event Day

Notification	Size group	# Customers	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)
No	Large	369	320.4	10.8	4.0
	Medium	4,180	23.9	0.1	0.4
	Small	30,567	1.1	<0.1	0.4
	All	**35,116**	**7.1**	**0.1**	**4.7**
Yes	Large	1,526	138.7	2.9	4.4
	Medium	25,401	22.4	0.1	3.0
	Small	182,048	1.4	<0.1	0.4
	All	**208,975**	**4.9**	**<0.1**	**7.8**

In Figure 4-26 below we compare the average event hour impacts on each event day, by notification, for all customers in PY2020.

Figure 4-26 Comparison Average Event-Hour of Impacts by Level of Communication



SDG&E

This section presents the ex-post load impact analysis for SDG&E. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the typical event day, which is simply the average of all the event days, as well as for each individual event. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

Table 4-33 below summarizes the overall program level event-hour impacts on each event including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Note that in PY2020, SDG&E called three weekend events: September 5th, 6th, and 7th.

Table 4-33 SDG&E All Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	13,595	639.8	3.7	47.1	0.3	0.59%	87.1
August 18	13,605	653.6	6.9	48.0	0.5	1.06%	85.2
August 19	13,608	658.4	6.9	48.4	0.5	1.05%	86.3
August 20	13,615	652.2	6.7	47.9	0.5	1.02%	83.7
September 5	13,706	571.4	6.0	41.7	0.4	1.05%	96.5
September 6	13,706	559.6	3.2	40.8	0.2	0.57%	98.6

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
September 7	13,706	521.2	4.0	38.0	0.3	0.77%	78.7
September 30	13,768	686.8	6.1	49.9	0.4	0.88%	94.2
October 1	13,766	677.3	6.1	49.2	0.4	0.90%	92.6
Typical Event Day	**13,675**	**624.5**	**5.5**	**45.7**	**0.4**	**0.88%**	**89.2**

Comparison of Ex-Post Impacts

In Table 4-34 and Table 4-35 below we present the comparison of current ex-post impacts to previous ex-post impacts, and current ex-post impacts to prior ex-ante impacts. These comparisons give the reader with a sense of how the program has performed over time, and how the program has performed relative to the most recent forecast.

Table 4-34 SDG&E Non-Residential CPP: Previous and Current Ex-Post, Typical Event Day

Program Year	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
2018	Large	1,211	348.1	6.9	287.5	5.7	2.00%	88.5
	Medium	12,854	437.5	1.9	34.0	0.2	0.40%	88.2
	All	**14,065**	**785.6**	**8.8**	**55.9**	**0.6**	**1.12%**	**88.2**
2020	Large	1,431	297.5	5.3	207.9	3.7	1.79%	89.4
	Medium	12,244	327.0	0.2	26.7	<0.1	0.06%	89.1
	All	**13,675**	**624.5**	**5.5**	**45.7**	**0.4**	**0.88%**	**89.2**

Table 4-34 above, presents the ex-post from PY2018 compared to PY2020. SDG&E's non-residential CPP program has decreased in participants, and in total impacts, and percent impacts compared to PY2018. Impact reductions were small at the percent impact level, however coupled with significant reductions in reference loads the overall impacts fell from 8.8 MW in PY2018 to 5.5 MW in PY2020 despite the warmer temperatures.

In Table 4-35 below, we present the PY2020 ex-post impacts compared to prior ex-ante impacts. Overall, total MW impacts are smaller in PY2020 relative to PY2018 based on the reduced responsiveness of the large customers.

Table 4-35 SDG&E Non-Residential CPP: Previous Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2020) and Current Ex-Post (Typical Event Day), 2 PM to 6 PM

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante	Large	1,289	252.2	6.7	195.6	5.2	2.65%	85.1
	Medium	12,840	311.1	0.4	24.2	<0.1	0.12%	84.7
	All	**14,129**	**563.2**	**7.0**	**39.9**	**0.5**	**1.25%**	**84.8**
Current Ex-Post	Large	1,431	297.5	5.3	207.9	3.7	1.79%	89.4
	Medium	12,244	327.0	0.2	26.7	<0.1	0.06%	89.1
	All	**13,675**	**624.5**	**5.5**	**45.7**	**0.4**	**0.88%**	**89.2**

Results for Large Customers (≥ 200 kW)

This section summarizes results for all large SDG&E program participants, defined as customers with maximum demand equal to, or greater than, 200 kW. The results are presented as follows:

- Average event-hour impacts for each individual event day
- Hourly load impacts for a typical event day
- Average event-hour impacts on a typical event day by industry group and LCA

Results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent subsections.

Figure 4-27 presents the average event-hour ex post load impacts for each individual event day for all of SDG&E's large PDP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

These results indicate that large customers had statistically significant load reductions on four of the nine event days, ranging from 4.1 to 6.2 MW. The average load impact was 5.3 MW, with five out of nine event days having a load impact greater than 5.0 MW.

Figure 4-27 SDG&E Large all Participants: Average Event-Hour Impacts by Event

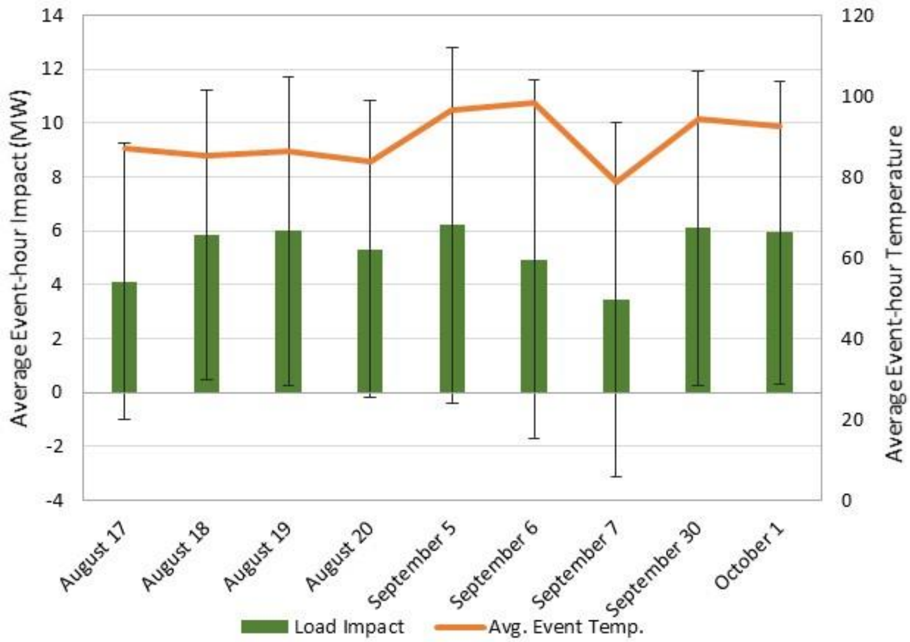


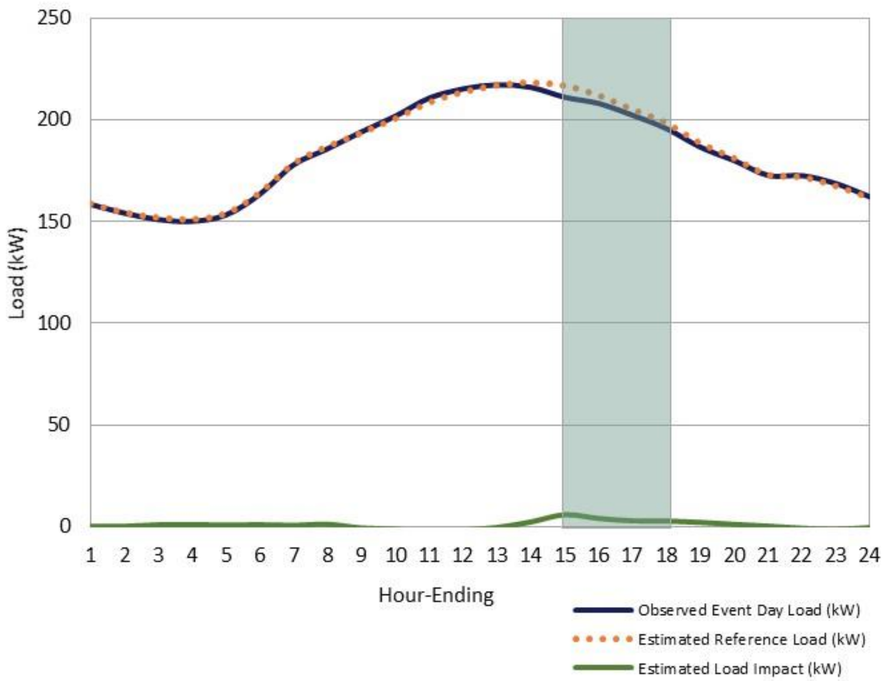
Table 4-36 summarizes the event-hour impacts on each event including the number of participants enrolled during each event, the aggregate and per-customer reference load and load impacts, the percent impact, and the average temperature. Load impacts as a percent of the reference load were 1.79% on average across the nine events. In addition, enrollment increased slightly over time from 1,427 participants during the first event on August 17th to 1,438 participants on the last October 1st event.

Table 4-36 SDG&E Large all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	1,427	306.0	4.1	214.4	2.9	1.35%	87.2
August 18	1,427	312.7	5.9	219.2	4.1	1.87%	85.3
August 19	1,427	315.7	6.0	221.2	4.2	1.90%	86.5
August 20	1,427	311.4	5.3	218.3	3.7	1.71%	83.8
September 5	1,432	268.0	6.2	187.2	4.3	2.32%	96.8
September 6	1,432	264.5	4.9	184.7	3.5	1.87%	98.6
September 7	1,432	250.7	3.4	175.1	2.4	1.37%	78.8
September 30	1,438	327.3	6.1	227.6	4.2	1.86%	94.4
October 1	1,438	321.2	5.9	223.4	4.1	1.85%	92.8
Typical Event Day	**1,431**	**297.5**	**5.3**	**207.9**	**3.7**	**1.79%**	**89.4**

Figure 4-28 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. The highest load impact tends to occur during the first event hour. In addition, hourly load impacts do not show evidence of pre-cooling or post-event snapback. This is more typical of large participants that tend to be less weather sensitive and participate using a mix of end-uses rather than being cooling dominated like SMB or residential customers. The load impacts outside the event windows are very small and do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

Figure 4-28 SDG&E Large all Participants: Hourly Typical Event Day Load Impacts



SDG&E Large: by Industry

Next, we look at load impacts for SDG&E large customers by industry group. Table 4-5 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Insignificant impacts are highlighted in red font.

Enrollments are concentrated in the Offices, Hotels, Finance, Services Industries, Schools and Manufacturing s groups. These groups represent 67% of the total enrolled customers. The largest estimated load impacts are from Offices, Hotels, Finance, Services Industries with an impact of 3.6 MW. This group contributes 67% of total load reduction. (See Figure 4-3.) Three of the industries, Agriculture, Mining & Construction, Manufacturing and Schools, show negative impacts.

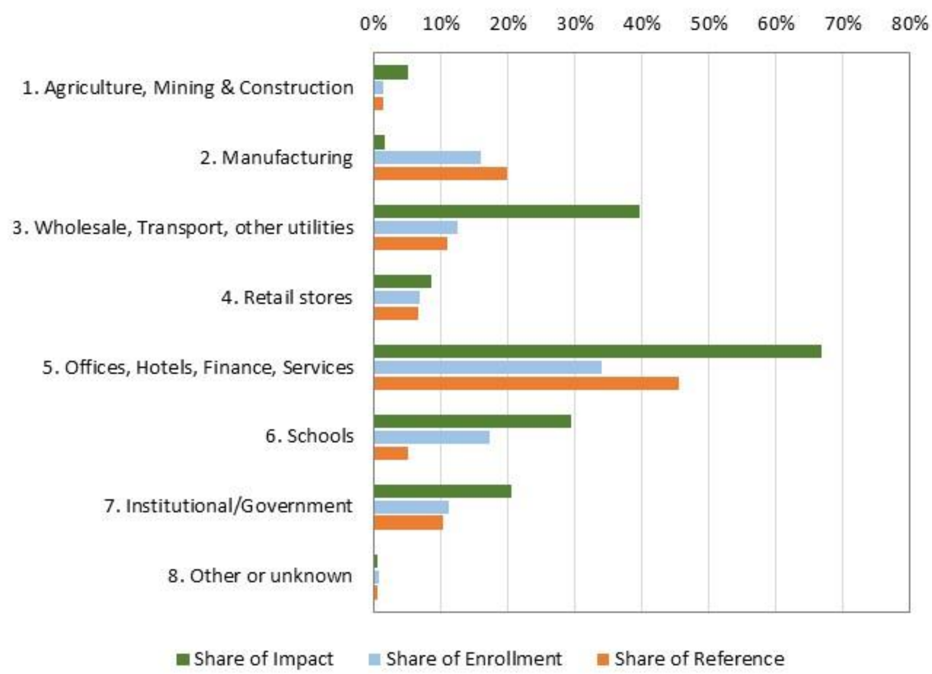
In Figure 4-29, we present the share of the total enrollment, impacts, and reference load by industry.[36]

[36] Note that the total share of impacts is based upon the absolute value of the impacts to properly normalize for both positive and negative impacts.

Table 4-37 SDG&E Large: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	19	4.1	-0.3	-6.62%	88.6
2. Manufacturing	230	58.9	-0.1	-0.14%	87.2
3. Wholesale, Transport, other utilities	179	32.6	2.1	6.49%	90.5
4. Retail stores	98	19.6	0.5	2.36%	88.6
5. Offices, Hotels, Finance, Services	487	135.2	3.6	2.63%	89.7
6. Schools	246	15.0	-1.6	-10.48%	91.3
7. Institutional/Government	161	30.7	1.1	3.55%	90.4
8. Other or unknown	10	1.5	0.0	1.95%	86.9

Figure 4-29 SDG&E Large: Contributions by Industry on a Typical Event Day



Results for Medium Customers (20 ≤ x < 200 kW)

This section summarizes results for all medium SDG&E program participants, defined as customers with maximum demand equal to or greater than 20 kW but less than 200 kW. The results are presented in the same format as the previous section. Again, results for dually enrolled customers, AutoDR customers, and for those that were notified (vs. not notified) are presented in subsequent sub-sections.

Figure 4-30 presents the average event-hour ex-post load impacts for each individual event day for all of SDG&E's medium PDP participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

These results indicate that medium PDP participants had statistically significant changes in usage on only four out of the nine event days. Furthermore, the point estimates are both positive and negative with an average per-customer impact of 0.02. AEG believes that this pattern of impacts suggests that the medium customers are not responding to PDP events and that their true impacts are in fact zero. Table 4-7 shows enrollment slightly increase over time from 12,168 participants during the first event to 12,328 participants on the last event.

Figure 4-30 SDG&E Medium all Participants: Average Event-Hour Impacts by Event

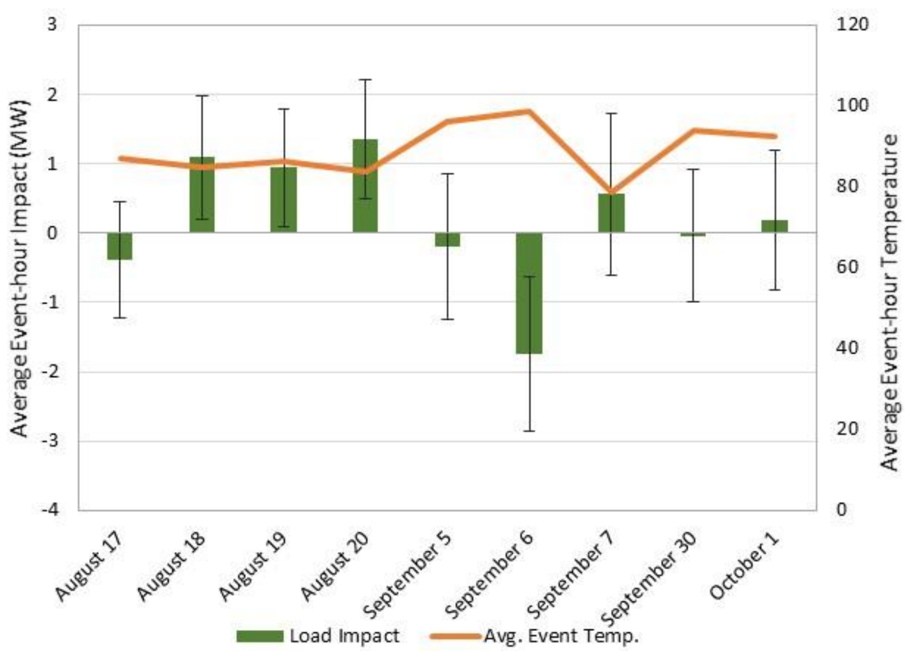
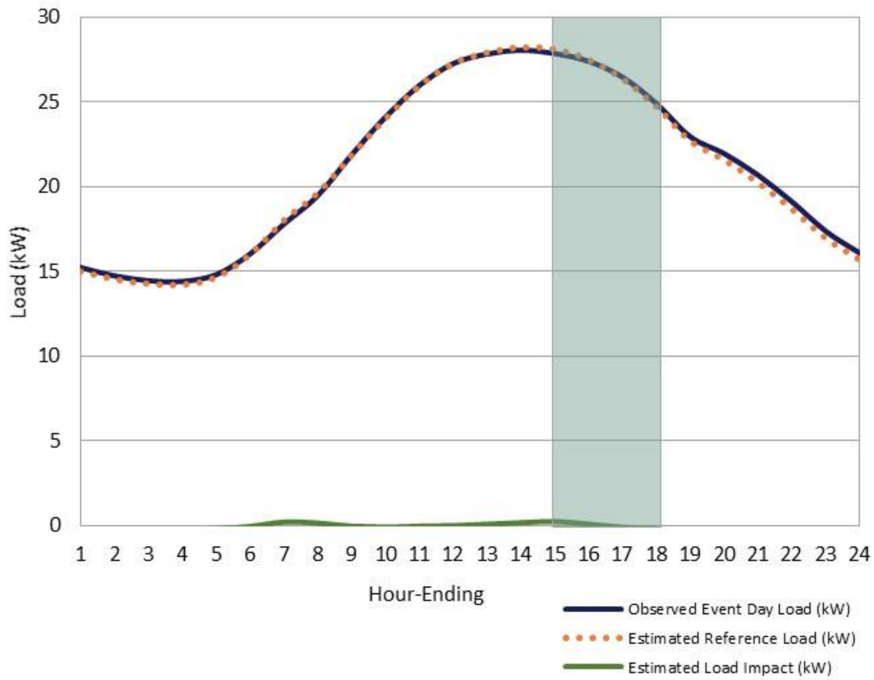


Table 4-38 SDG&E Medium all Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	12,168	333.8	-0.4	27.4	-0.03	-0.12%	87.0
August 18	12,178	340.9	1.1	28.0	0.09	0.32%	85.0
August 19	12,181	342.7	0.9	28.1	0.08	0.27%	86.2
August 20	12,188	340.8	1.3	28.0	0.11	0.40%	83.6
September 5	12,274	303.4	-0.2	24.7	-0.02	-0.06%	96.3
September 6	12,274	295.1	-1.7	24.0	-0.14	-0.59%	98.6
September 7	12,274	270.5	0.6	22.0	0.05	0.21%	78.6
September 30	12,330	359.4	0.0	29.2	0.00	-0.01%	94.0
October 1	12,328	356.1	0.2	28.9	0.02	0.05%	92.5
Typical Event Day	**12,244**	**327.0**	**0.2**	**26.7**	**0.02**	**0.06%**	**89.1**

Figure 4-31 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. The impacts in this case are extremely flat and the observed and reference loads show no visible differences on event days during the event window.

Figure 4-31 SDG&E Medium all Participants: Hourly Typical Event Day Load Impacts



SDG&E Medium: by Industry

Next, we look at load impacts for SDG&E's medium customers by industry group. Table 4-8 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, the estimated load impacts as a percentage of the reference load, and the average event temperature. Enrollments are concentrated in the Offices, Hotels, Finance & Services. This group represents 50% of the total enrolled customers. Three of the industries show negative impacts, Agriculture, Mining & Construction, Manufacturing and Offices, Hotels, Finances, Services.

Table 4-39 SDG&E Medium: Average Event-Hour Impacts by Industry on a Typical Event Day

Industry	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
1. Agriculture, Mining & Construction	398	8.7	0.0	-0.24%	88.7
2. Manufacturing	919	22.3	-0.2	-1.04%	89.2
3. Wholesale, Transport, other utilities	725	19.1	0.4	1.85%	87.5
4. Retail stores	1,672	59.0	0.9	1.49%	86.7
5. Offices, Hotels, Finance, Services	6,105	164.8	-1.6	-0.99%	89.8
6. Schools	490	11.4	0.2	1.89%	91.2
7. Institutional/Government	1,649	37.1	0.7	1.88%	90.4

Dually Enrolled Customers

Next, we present the impacts for SDG&E's dually enrolled customers. On a typical event day, a total of 40 customers were dually enrolled in either SDG&E's Capacity Bidding Program (CBP) or the Base Interruptible Program (BIP). These customers demonstrate consistent positive impacts ranging from 0.7 MW to 3.2 MW (0.75% to 2.8%) and impacts across each individual day was insignificant, however the overall impact on the typical event day was significant.

Figure 4-32Figure 4-9 presents the average event-hour ex-post load impacts for each individual event day for the dually enrolled customers. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-32 SDG&E Dually Enrolled Participants: Average Event-Hour Impacts by Event

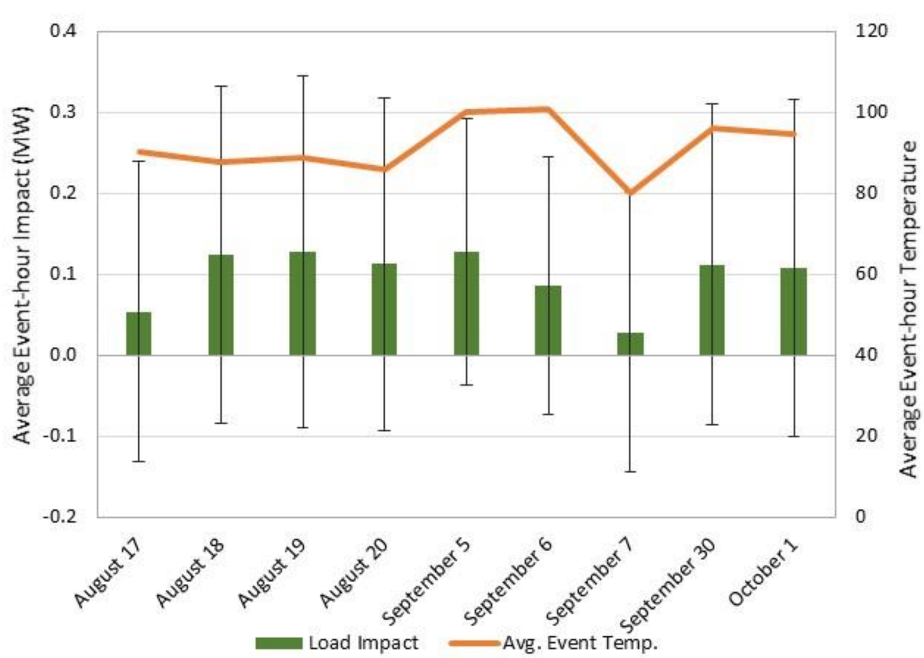


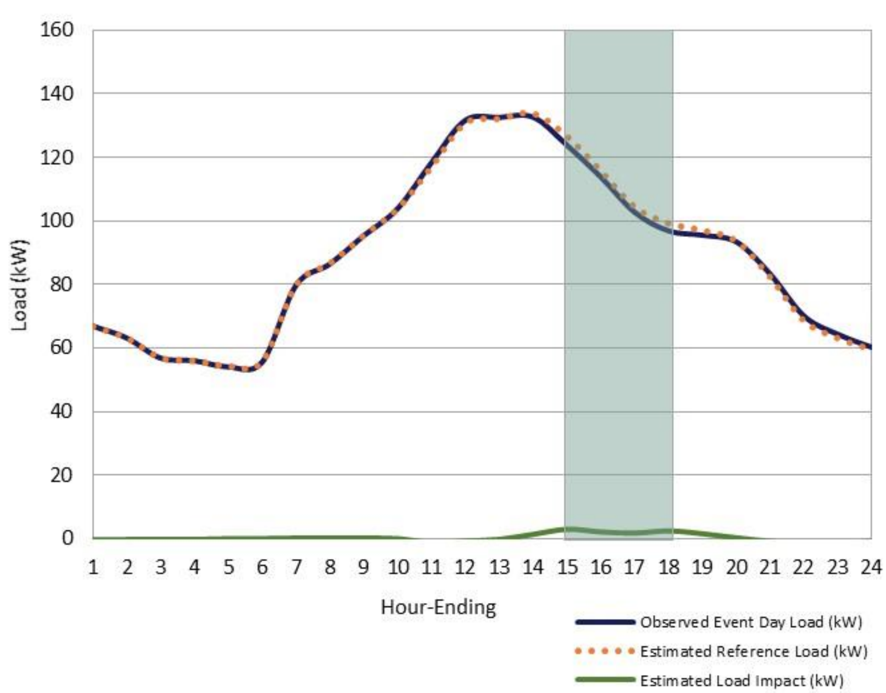
Table 4-40, presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day. Insignificant impacts are identified in red fo nt.

Table 4-40 SDG&E Dually Enrolled Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	39	4.1	0.1	105.5	1.4	1.31%	90.3
August 18	40	4.4	0.1	109.9	3.1	2.82%	87.7
August 19	40	4.9	0.1	122.6	3.2	2.60%	88.8
August 20	40	4.4	0.1	109.6	2.8	2.56%	85.8
September 5	40	4.7	0.1	118.5	3.2	2.68%	100.1
September 6	40	4.7	0.1	118.5	2.1	1.81%	100.7
September 7	40	3.7	0.0	93.0	0.7	0.75%	80.1
September 30	40	4.6	0.1	114.2	2.8	2.45%	95.9
October 1	40	4.5	0.1	112.4	2.7	2.40%	94.5
Typical Event Day	**40**	**4.5**	**0.1**	**111.6**	**2.4**	**2.19%**	**91.5**

Figure 4-33 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day.

Figure 4-33 SDG&E Dually Enrolled Participants: Hourly Typical Event Day Load Impacts



Automated Demand Response Customers

Next, we present the impacts for SDG&E's Automated Demand Response (AutoDR) customers. SDG&E's AutoDR customers have load reduction equipment installed at their facilities which automates their response during events. Only 1 customer participated in the AutoDR program. This customer demonstrated consistent very small positive impacts with an average of 0.12 MW. Six of the nine impacts were statistically significant due to the low number of participants.

Figure 4-34 presents the average event-hour ex post load impacts for each individual event day for all of SDG&E's AutoDR participants. The green bars indicate the magnitude of the aggregate load impact and the black bands correspond to 90 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the participants during the event hours.

Figure 4-34 SDG&E AutoDR Participants: Average Event-Hour Impacts by Event

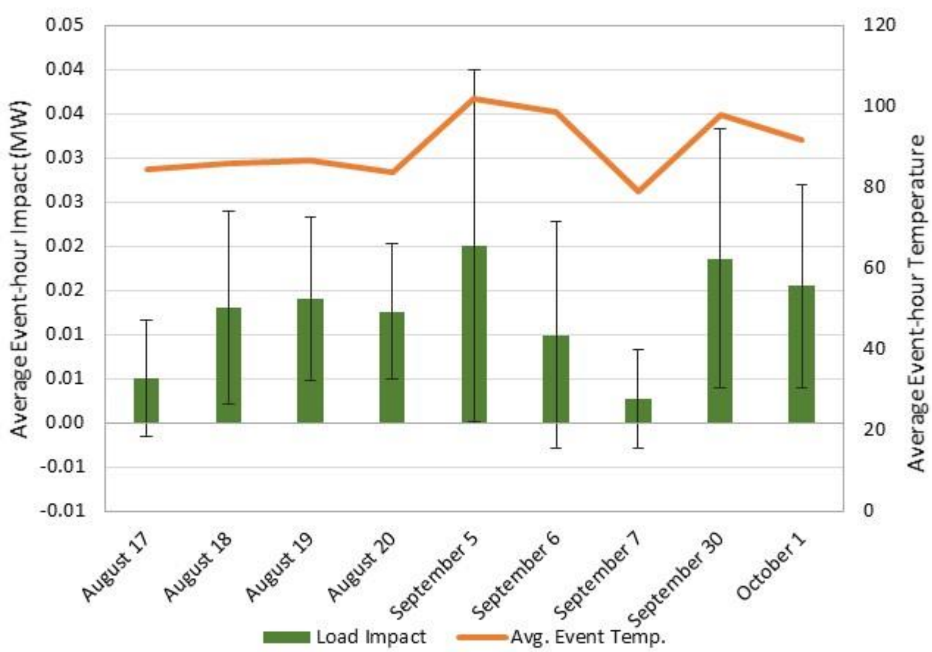


Table 4-41 presents both the aggregate and per-customer impacts, the percent impacts, the number of participants enrolled, and the temperature on each day.

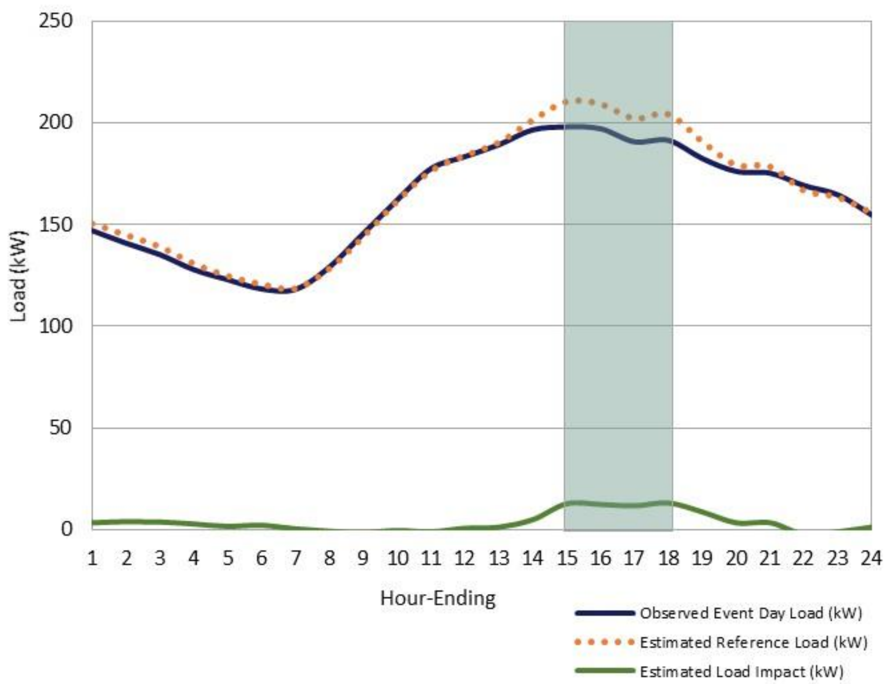
Table 4-41 SDG&E AutoDR Participants: Average Event-Hour Impacts by Event

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
August 17	1	0.2	<0.1	210.6	5.0	2.35%	84.3
August 18	1	0.2	<0.1	220.7	13.1	5.92%	85.8
August 19	1	0.2	<0.1	216.7	14.0	6.47%	86.8
August 20	1	0.2	<0.1	208.1	12.6	6.04%	83.8

Event Date	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
September 5	1	0.2	<0.1	248.6	20.0	8.05%	101.8
September 6	1	0.2	<0.1	214.3	9.9	4.63%	98.5
September 7	1	0.2	<0.1	165.3	2.7	1.62%	79.0
September 30	1	0.2	<0.1	186.7	18.5	9.93%	97.8
October 1	1	0.2	<0.1	189.8	15.4	8.13%	91.5
Typical Event Day	**1**	**0.2**	**<0.1**	**206.8**	**12.4**	**5.98%**	**89.9**

Figure 4-35 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Notice that impacts outside the event window are very small relative the event window impacts indicating a consistent load reduction without shifting of load into non-event hours.

Figure 4-35 SDG&E AutoDR Participants: Hourly Typical Event Day Load Impacts



Notified vs. Non-Notified Customers

PDP is a default rate for SDG&E's non-residential customers and as such, participants are notified of an event if their contact information is provided to SDG&E. However, customers that do not receive notification probably do not know that an event is occurring and would therefore find it difficult to respond. Customers can receive day ahead notifications for events by setting up their account to receive alerts either by email, or by text message. SDG&E discontinued their in-season support this year, which provided additional information including post event feedback to participants.

Table 4-13 and Table 4-16 present the percentage of service accounts receiving notification by size group and the per-customer impacts by size group, and notification, on a typical event day, respectively.

In looking at Table 4-42, we note that relative to last year SDG&E saw a decrease in the percentage of service accounts receiving notification 92% to 50%. But, similar to last year, approximately 93% of the load impacts come from customers that are receiving notification. However, when we compare the difference in per-customer impacts by size, in Table 4-43, we can see that the key difference, at a per-customer level, comes from the large customers. The small and medium customers show negligible reductions regardless of whether they are notified of events suggesting that for these groups, notifications and/or increasing notifications will not improve the impacts.

Table 4-42 Percent of Service Accounts Receiving Notification, by Size Group: Typical Event Day

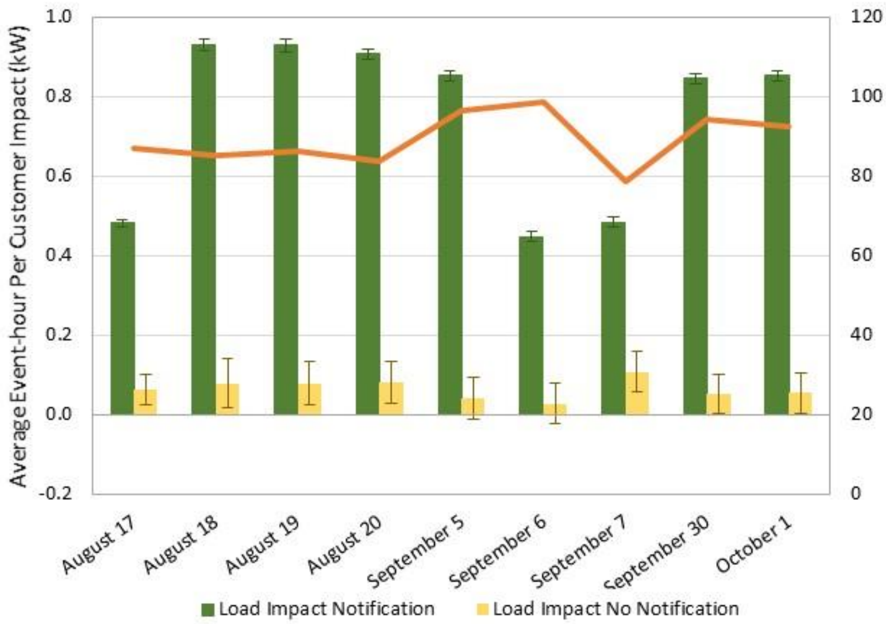
Size Group	SDG&E % Notified
Large (≥ 200 kW)	63%
Medium (20 kW ≤ x < 200 kW)	48%
Total	**50%**

Table 4-43 Per-Customer Impacts by Size Group and Notification: Typical Event Day

Notification	Size group	# Customers	Per-Customer Ref. Load (kW)	Per-Customer Load Impact (kW)	Aggregate Load Impact (MW)
No	Large	532	217.8	0.7	0.4
	Medium	6,362	26.7	0.0	0.1
	All	**6,893**	**41.5**	**0.1**	**0.4**
Yes	Large	899	202.0	5.5	5.0
	Medium	5,882	26.7	0.0	0.1
	All	**6,782**	**49.9**	**0.7**	**5.1**

In Figure 4-36 below we compare the average event hour impacts on each event day, by notification, for all customers in PY2019.

Figure 4-36 Comparison Average Event-Hour of Impacts by Level of Communication; Large Customers



5

EX-ANTE RESULTS

This section presents the ex-ante results, which include the load impact forecasts for the 1-in-2 and 1-in-10 weather conditions for each IOU. For each utility we first present a summary COVID effect and adjustment, we then summarize the enrollment forecast and load impacts. Finally, we discuss the ex-ante impacts relative to current ex-post estimates and previous ex-ante results.

Unless specified otherwise, all estimates reported are for the resource adequacy (RA) window, which shifted to 4-9 PM (from 2-6 PM) starting in 2018. SCE has aligned their CPP event window with the RA window, and PG&E's event window is shifting to 5-8 PM[37] effective March 2021. However, SDG&E's event windows will remain unchanged, which means that the SDG&E's CPP program is only available during the first two hours of the RA window while all other hours are non-event hours. This results in significantly lower (and sometimes even negative) impacts within the RA window.

PG&E

In the subsections that follow, we present the results of the COVID adjustment and the ex-ante impacts along with a comparison on ex-ante impacts across years.

COVID Effect and Adjustment

In Section 3, Study Methods, we describe the methodology that was used to estimate the effect of COVID-19 stay-at-home orders and other shutdowns on the per-customer reference loads. We also describe how those effects were used to adjust the ex-ante forecast of the reference load. The purpose of the adjustment is to bring the reference load back to a level that represents a no-COVID world. PG&E's forecast assumes that the effect of COVID will drop by half each year, beginning in 2021, and will completely disappear by 2024. The adjusted reference load increases and separates from the unadjusted load, representing a return to "normal" or a no-COVID state. The largest effect is seen in the small group, which aligns with our expectations that the shutdowns and stay-at-home orders impacted small businesses more than larger businesses in 2020.

Ex-Ante Enrollment and Load Impact Summary

Effective March 2021, PDP's event window will be from 5 to 8 PM. To incorporate these expected changes into the forecast, AEG used the following assumptions:

- We maintained the 2 to 6 PM event window in the 2020 "back-cast" and 2021 January and February monthly peak scenarios.
- Starting from the 2021 March monthly peak scenario, we shifted the event window to 5 to 8 PM by applying the hourly percent impacts to the hourly reference load. We did this for the event window, two pre-event hours, and two post-event hours.
    - o We used percent impacts to account for the change in available load under the new event window, which could be more or less depending on the customer industry type.

[37] Pending CPUC decision for R.20-11-003, the PDP event window is expected to be modified to 4 to 9 PM at a later point.

- o We included the pre-event and post-event hours to incorporate any pre-cooling and snapback behaviors, which are evident in some participant segments.

- Using SCE's historical experience in shifting the CPP event window, we assumed a 50% decrease in load impacts during the first year of the event window shift. Load impacts are assumed to be 100% or "back to normal" from the second year through the remainder of the forecast.

Table 5-1 summarizes the average event-hour load impact forecasts for non-residential PDP participants on a typical event day in 2021. The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. As noted in the ex-post analysis, the largest impacts come from the large group, even though they have the fewest participants. The small and medium groups are also significant contributors this year with a combined 35% share of impacts.

Table 5-1 PG&E Typical Event Enrollment and Impacts by Size: 2021

Size	# of Accts	Aggregate Impact (MW)				Per-Customer Impact (kW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Large	2,106	7.71	7.79	7.48	7.75	3.66	3.70	3.55	3.68
Medium	19,352	2.41	2.48	2.23	2.42	0.12	0.13	0.12	0.12
Small	105,124	1.65	1.79	1.44	1.68	0.02	0.02	0.01	0.02
Total CPP	**126,582**	**11.77**	**12.06**	**11.15**	**11.85**	**0.09**	**0.10**	**0.09**	**0.09**

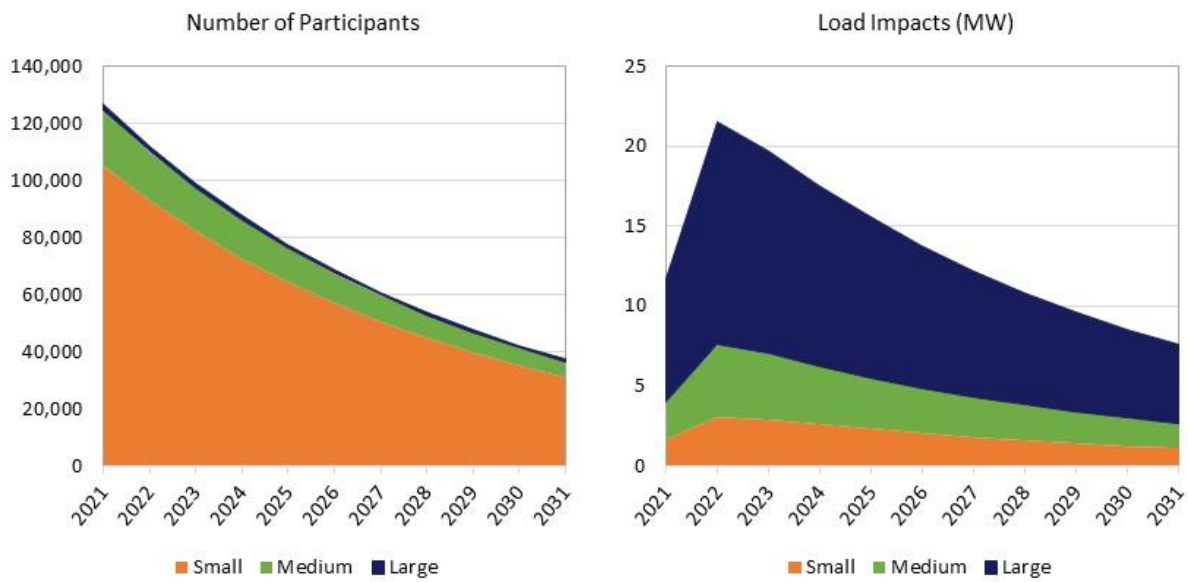
In Table 5-2 below, we also present the program level impacts by month for a PG&E 1-in-2 weather year for 2021, 2024, and 2031. Enrollment shows small fluctuations across months, which is expected in typical participant enrollment and attrition. Impacts are weather sensitive with the highest impacts occurring in the summer months: June through September.

Table 5-2 PG&E Monthly Program Level Enrollment and Impacts for Selected Years: PG&E 1-in-2

Month	2021		2024		2031	
	Enrollment	Impact (MW)	Enrollment	Impact (MW)	Enrollment	Impact (MW)
January	99,675	7.70	94,204	7.05	40,052	3.10
February	98,665	7.64	93,250	7.00	39,642	3.06
March	133,195	5.68	92,305	8.44	39,241	3.69
April	131,844	9.18	91,370	13.67	38,845	5.95
May	130,508	10.65	90,442	15.89	38,451	6.88
June	129,186	12.23	89,527	18.29	38,062	7.93
July	127,876	12.35	88,617	18.43	37,676	7.97
August	126,582	11.90	87,721	17.71	37,295	7.67
September	125,296	11.50	86,833	17.12	36,918	7.42
October	124,028	9.19	85,953	13.59	36,545	5.91
November	122,770	4.30	85,080	6.31	36,173	2.79
December	121,525	4.27	84,220	6.26	35,807	2.76

In Figure 5-1 below, we present side-by-side comparisons of PG&E's 11-year annual enrollment and impact forecasts for a utility 1-in-2 weather scenario on a typical event day. PG&E is defaulting a group of new participants in March 2021 but expects a decrease in enrollment over time with no further defaults scheduled for future years. Also, effective in March 2021 is a new event window that is more coincident with the RA window. We assume a 50% decrease in load impacts in the first year of the new event window to account for the "learning curve" as participants adjust their behaviors. From the second year, 2022, we assume that load impacts will return to normal levels.

Figure 5-1 PG&E Enrollment and Impact Forecast: PG&E 1-in-2, Typical Event Day, 2021 - 2031



Comparison of Ex-Ante Impacts

In Table 5-3 below, we compare the current ex-post with the current ex-ante. Note that this comparison shows the average estimates for the PDP event window (2 to 6 PM). This comparison highlights the effect of adjusting the impacts and reference loads to reflect the various weather scenarios required in the analysis. Here, we compare the ex-post to a 1-in-2 weather year, which is slightly milder than a 1-in-2 weather year. The results indicate that the ex-post impacts, while experiencing some extreme weather in parts of PG&E's territory, were on the whole slightly below normal, with the 1-in-2 impacts being just a bit higher than the ex-post impacts across the board.

Table 5-3 PG&E Non-Residential CPP: Current Ex-Post (Typical Event Day) and Current Ex-Ante (PG&E 1-in-2, Typical Event Day, 2020), 2 to 6 PM.

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Current Ex-Post	Large	865	220.2	7.7	254.6	8.9	3.49%	96.4
	Medium	13,914	382.6	4.6	27.5	0.3	1.21%	95.9
	Small	86,850	204.2	3.8	2.4	0.0	1.85%	92.5
	All	**101,629**	**807.0**	**16.1**	**7.9**	**0.2**	**1.99%**	**94.8**
Current Ex-Ante	Large	861	227.6	7.9	264.3	9.2	3.48%	99.8
	Medium	13,899	371.1	5.4	26.7	0.4	1.45%	99.5
	Small	86,831	207.6	4.3	2.4	0.0	2.05%	98.2
	All	**101,591**	**806.3**	**17.6**	**7.9**	**0.2**	**2.18%**	**98.4**

In Table 5-4, we compare the previous ex-ante forecast from PY2019 to the current ex-post forecast from PY2020 in both 2021 and 2024. We include both years because 2021 is still affected by COVID conditions and the first year of the new event window, while by 2024, we start to see a return to a no-COVID case and assume load impacts are "back to normal". A couple of key highlights include the following.

- Comparing the aggregate load impacts in MW between the two 2021 forecasts, we see an increase from 8.3 MW to 11.8 MW. This is coming primarily from the new event window (5-8 PM) shifting to coincide with the RA window (4-9 PM), increasing the load impacts available during the RA window, despite assuming that 2021 will likely see a decrease in load impacts due participants adjusting to the new event window.
- Comparing the aggregate load impacts in MW between the PY2020 2021 and PY2020 2024 forecasts, we see an increase from 11.8 MW to 17.5 MW despite the expected participant attrition starting in 2022. This is primarily due to the assumption that participants will fully adjust to the new event window after the second year resulting in double the average per-customer impacts from 0.1 kW in 2021 to 0.2 kW in 2024.
- Comparing the reference loads between the PY2019 – 2021 forecast and PY2020 - 2024 forecasts, we see that the per-customer reference loads are closer to PY2019 (pre-COVID) levels as a result of the COVID adjustments. It is important to note that PG&E's PDP population experienced a significant migration from the large group to the medium group and from the medium group to small group,[38] and we see the effects of that migration in all three groups. The PY2020 – 2024 forecast shows:
    - The large group still slightly smaller than pre-COVID levels.
    - The medium and small groups still slightly larger than pre-COVID levels.

[38] It is unclear whether the migration between customer size groups is a result of COVID conditions or, a result of some reclassification efforts on PG&E's side. Therefore, we maintain the existing size group distribution of participants throughout the ex-ante forecast.

Table 5-4 PG&E Non-Residential CPP: Previous and Current Ex-Ante, PG&E 1-in-2, Typical Event Day

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante (2021)	Large	2,570	789.6	10.7	307.3	4.2	1.36%	94.1
	Medium	33,456	677.1	-1.6	20.2	<0.1	-0.24%	94.0
	Small	127,703	193.8	-0.8	1.5	<0.1	-0.40%	92.8
	All	**163,729**	**1,660.5**	**8.3**	**10.1**	**0.1**	**0.50%**	**93.1**
Current Ex-Ante (2021)	Large	2,106	590.9	7.7	280.6	3.7	1.31%	95.6
	Medium	19,352	479.7	2.4	24.8	0.1	0.50%	95.6
	Small	105,124	214.2	1.6	2.0	<0.1	0.77%	93.7
	All	**126,582**	**1,284.8**	**11.8**	**10.1**	**0.1**	**0.92%**	**94.0**
Current Ex-Ante (2024)	Large	1,465	431.1	11.3	294.2	7.7	2.61%	95.6
	Medium	13,416	365.0	3.7	27.2	0.3	1.00%	95.6
	Small	72,840	168.3	2.6	2.3	<0.1	1.54%	93.7
	All	**87,721**	**964.4**	**17.5**	**11.0**	**0.2**	**1.82%**	**94.0**

SCE

In the subsections that follow, we present the results of the COVID adjustment and the ex-ante impacts along with a comparison on ex-ante impacts across years.

COVID Effect and Adjustment

Consistent with PG&E, we estimated the effect of COVID-19 stay-at-home orders and other shutdowns on the per-customer reference loads and used those effects to adjust the ex-ante forecast of the reference load. The purpose of the adjustment is to bring the reference load back to a level that represents a no-COVID world. SCE's forecast assumes that the effect of COVID will drop by half each year, beginning in 2021, and will completely disappear by 2025.

Below in Figure 5-2 and associated Table 5-5, we present the estimated COVID effect and adjusted references loads for the program as a whole. Note that the adjusted and unadjusted reference loads are the same in 2020 since the full effect of COVID was assumed to occur during that year. In later years, the adjusted reference load increases and separates from the unadjusted load, representing a return to "normal" or a no-COVID state. Note that the average adjustment in 2025 is equal to the effect we estimated from our simple regression model at 0.65kW per-customer or about 13% of the reference load. In other words, COVID-19 conditions resulted in a 13% reduction in on-peak consumption, on average for SCE's CPP participants.

Figure 5-2 SCE Average Per-Customer Adjusted and Unadjusted Reference Load Forecast

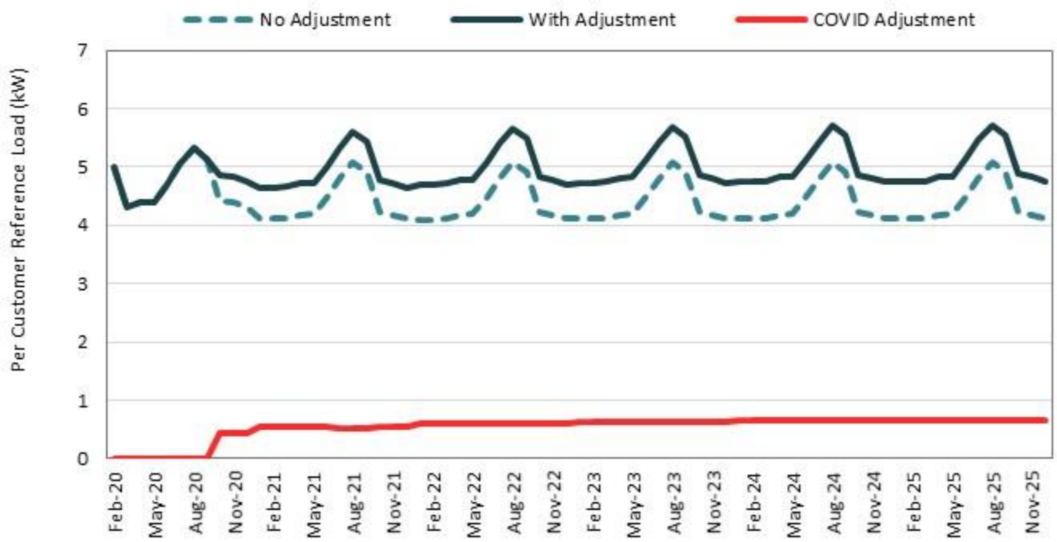


Table 5-5 SCE Average Per-Customer Reference Load Forecast and COVID-19 Adjustment

Month	Year	Enrollment Forecast	Reference Load No Adjustment	Reference Load With Adjustment	COVID Adjustment
August peak day	2020	244,066	5.32	5.32	0.00
	2021	255,557	5.07	5.59	0.52
	2022	258,057	5.07	5.66	0.59
	2023	267,556	5.07	5.69	0.62
	2024	277,057	5.07	5.71	0.64
	2025	286,559	5.07	5.72	0.65

In Table 5-6 below, we also present the adjusted reference loads and the COVID adjustments by size group. The COVID effects are approximately 10% for both the large and medium customers groups, while the effect for the small group is slightly larger at 13%. This aligns with our expectations that the shutdowns and stay-at-home orders impacted small businesses more than larger businesses in 2020.

Table 5-6 SCE Per-Customer Reference Load Forecast and COVID-19 Adjustment, by Size

Year	Large		Medium		Small	
	Adjusted Reference Load	COVID Adjustment	Adjusted Reference Load	COVID Adjustment	Adjusted Reference Load	COVID Adjustment
2020	**176.66**	0.00	22.70	0.00	1.38	0.00
2021	192.40	15.78	24.64	1.93	1.59	0.21
2022	194.78	18.14	24.94	2.24	1.61	0.23
2023	195.96	19.33	25.09	2.39	1.62	0.24
2024	196.55	19.92	25.17	2.46	1.63	0.25
2025	196.84	20.21	25.20	2.50	1.63	0.25

Ex-Ante Enrollment and Load Impact Summary

Table 5-7 summarizes the average event-hour load impact forecasts for non-residential CPP participants on a typical event day in 2021. The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. As noted in the ex-post analysis, the largest impacts come from the large group, even though they have the fewest participants. The medium group is a significant contributor this year with close to one third of the impacts, while the small group has positive, but insignificant results.

Table 5-7 SCE Typical Event Enrollment and Impacts by Size: 2021

Size	# of Accts	Aggregate Impact (MW)				Per-Customer Impact (kW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Large	1,905	9.6	10.4	9.6	10.1	5.0	5.5	5.0	5.3
Medium	28,560	3.7	4.6	3.6	4.2	0.1	0.2	0.1	0.1
Small	225,092	0.7	0.3	0.7	0.5	<0.1	<0.1	<0.1	<0.1
Total CPP	**255,557**	**14.0**	**15.3**	**13.9**	**14.8**	**0.1**	**0.1**	**0.1**	**0.1**

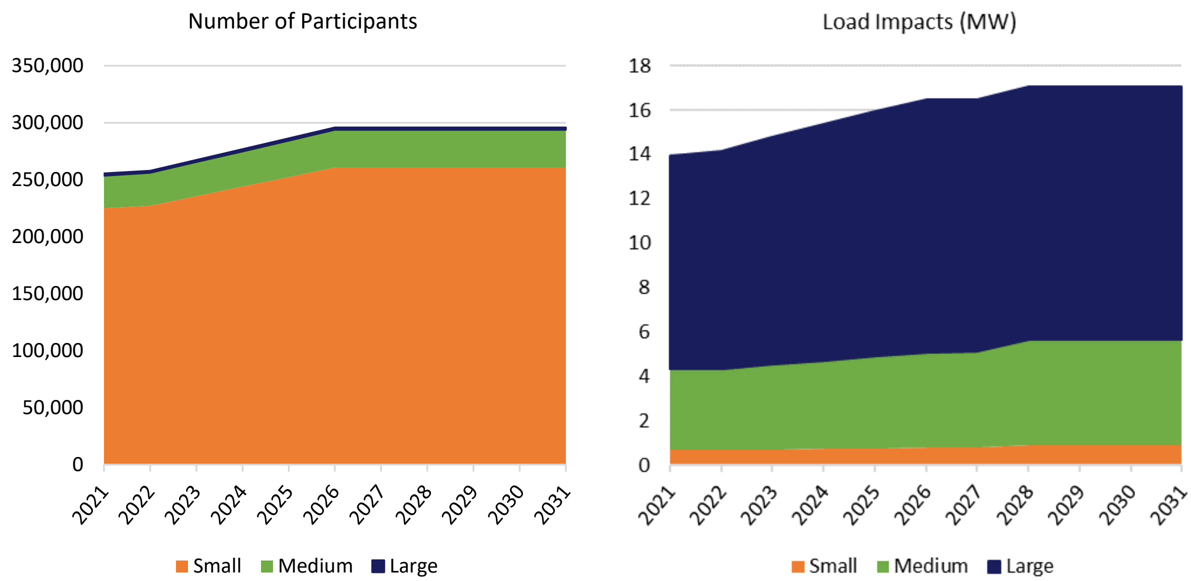
In Table 5-8 below, we also present the program level impacts by month for a SCE 1-in-2 weather year for 2021, 2025, and 2031. Enrollment is consistent across all months. Impacts are weather sensitive with the highest impacts occurring in September, and the lowest impacts occurring in December, January, February, and March.

Table 5-8 SCE Monthly Program Level Enrollment and Impacts for Selected Years: SCE 1-in-2

Month	2021		2025		2031	
	Enrollment	Impact (MW)	Enrollment	Impact (MW)	Enrollment	Impact (MW)
January	255,557	9.66	286,559	11.05	296,059	11.69
February	255,557	9.66	286,559	11.05	296,059	11.69
March	255,557	9.83	286,559	11.24	296,059	11.91
April	255,557	12.78	286,559	14.60	296,059	15.58
May	255,557	12.86	286,559	14.69	296,059	15.69
June	255,557	13.08	286,559	14.93	296,059	15.98
July	255,557	14.29	286,559	16.31	296,059	17.48
August	255,557	14.04	286,559	16.02	296,059	17.17
September	255,557	14.59	286,559	16.65	296,059	17.85
October	255,557	13.69	286,559	15.63	296,059	16.74
November	255,557	12.09	286,559	13.81	296,059	14.71
December	255,557	9.66	286,559	11.05	296,059	11.69

In Figure 5-3 below we present side-by-side comparisons of SCE’s 11-year annual enrollment and impact forecasts for a utility 1-in-2 weather scenario on a typical event day. As in previous years, while the Large participants make up only a small fraction of the enrollments, they account for the majority of the impacts. SCE also forecasts increased enrollment over time as customer are defaulted onto the CPP rate in the coming years to make up for de-enrollments due to customer churn and other factors.

Figure 5-3 SCE Enrollment and Impact Forecast: SCE 1-in-2, Typical Event Day, 2021 - 2031



Comparison of Ex-Ante Impacts

In Table 5-9 below, we compare the current ex-post with the current ex-ante. This comparison highlights the effect of adjusting the impacts and reference loads to reflect the various weather scenarios required in the analysis. Here, we compare the ex-post to a 1-in-2 weather year, which is close to normal. The results indicate that the ex-post impacts, while experiencing some extreme weather in parts of SCE's territory, were on the whole slightly below normal, with the 1-in-2 impacts being just a bit higher than the ex-post impacts across the board.

Table 5-9 SCE Non-Residential CPP: Current Ex-Post (Typical Event Day) and Current Ex-Ante (SCE 1-in-2, Typical Event Day, 2020)

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Current Ex-Post	Large	1,895	330.0	8.3	174.1	4.4	2.53%	87.2
	Medium	29,581	668.6	3.4	22.6	0.1	0.51%	84.4
	Small	212,615	284.1	0.8	1.3	<0.1	0.28%	81.2
	All	**244,091**	**1,282.6**	**12.5**	**5.3**	**0.1**	**0.98%**	**84.6**
Current Ex-Ante	Large	1,892	334.2	8.8	176.6	4.6	2.62%	87.8
	Medium	29,571	670.1	3.8	22.7	0.1	0.57%	87.5
	Small	212,604	292.9	0.6	1.4	<0.1	0.21%	87.0
	All	**244,067**	**1,297.2**	**13.2**	**5.3**	**0.1**	**1.02%**	**87.1**

In Table 5-10, we compare the previous ex-ante forecast from PY2019 to the current ex-post forecast from PY2020 in both 2020 and 2025. We include both years because 2020 is still affected by COVID conditions while by 2025 the SCE forecast assumes a return to a no-COVID case. A couple of key highlights include the following.

- Comparing the aggregate load impacts in MW between the two 2020 forecasts, we see an increase from 8.0 MW to 13.2 MW. This is coming primarily from the additional measurable impacts in the small and medium group. Increases in per-customer percent impacts across all groups also contribute to the increase.
- Comparing the reference loads between the PY2019 - 2020 and PY2020 - 2025 forecasts, we see that the per-customer reference loads return to very close to PY2019 (pre-COVID) levels as a result of the COVID adjustments.

Table 5-10 SCE Non-Residential CPP: Previous and Current Ex-Ante, SCE 1-in-2, Typical Event Day

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante (2020)	Large	2,525	498.2	8.0	197.3	3.2	1.60%	88.2
	Medium	30,298	750.1	0.0	24.8	0.0	0.00%	87.9
	Small	219,658	328.9	0.0	1.5	0.0	0.00%	87.1
	All	**252,481**	**1,577.2**	**8.0**	**6.2**	**<0.1**	**0.51%**	**87.2**
Current Ex-Ante (2020)	Large	1,892	334.2	8.8	176.6	4.6	2.62%	87.8
	Medium	29,571	670.1	3.8	22.7	0.1	0.57%	87.5
	Small	212,604	292.9	0.6	1.4	<0.1	0.21%	87.0
	All	**244,067**	**1,297.2**	**13.2**	**5.3**	**0.1**	**1.02%**	**87.1**
Current Ex-Ante (2025)	Large	2,136	420.4	11.0	196.8	5.2	2.62%	87.8
	Medium	32,027	805.8	4.1	25.2	0.1	0.51%	87.5
	Small	252,396	410.2	0.8	1.6	<0.1	0.19%	87.0
	All	**286,559**	**1,636.5**	**15.9**	**5.7**	**0.1**	**0.97%**	**87.1**

SDG&E

In the subsections that follow we present the results of the COVID adjustment and the ex-ante impacts along with a comparison on ex-ante impacts across years.

COVID Effect and Adjustment

Consistent with PG&E and SCE, we estimated the effect of COVID-19 stay-at-home orders and other shutdowns on the per-customer reference loads and used those effects to adjust the ex-ante forecast of the reference load. The purpose of the adjustment is to bring the reference load back to a level that represents a no-COVID world. SDG&E's forecast assumes that the effect of COVID will slowly drop in 2021 and will completely disappear by 2022.

Below in Figure 5-4 and associated Table 5-11, we present the estimated COVID effect and adjusted references loads for the program as a whole. Note that the adjusted and unadjusted reference loads are the same in 2020 since the full effect of COVID was assumed to occur during that year. In later years, the adjusted reference load increases and separates from the unadjusted load, representing a return to "normal" or a no-COVID state. Note that the average adjustment in 2022 is equal to the effect we estimated from our simple regression model, at 5.7 kW per-customer or about 15% of the reference load. In other words, COVID conditions resulted in a 15% reduction in on-peak consumption, on average for SDG&E's CPP participants.

Figure 5-4 SDG&E Average Per-Customer Adjusted and Unadjusted Reference Load Forecast

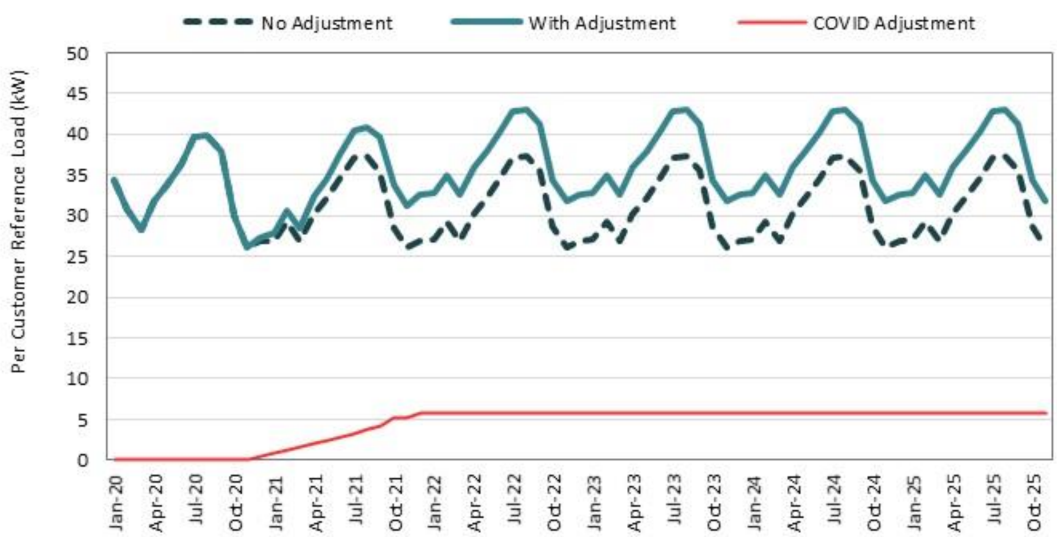


Table 5-11 SDG&E Average Per-Customer Reference Load Forecast and COVID-19 Adjustment

Month	Year	Enrollment Forecast	Reference Load No Adjustment	Reference Load With Adjustment	COVID Adjustment
August peak day	2020	13,606	39.7	39.7	0.0
	2021	8,320	37.1	40.4	3.3
	2022	4,950	37.1	42.8	5.7

In Table 5-12 below, we also present the adjusted reference loads and the COVID adjustments by size group. The COVID effects are approximately 12% for the large customer group, while the effect for the medium group is larger at 18%. This aligns with our expectations that the shutdowns and stay-at-home orders impacted smaller businesses more than larger businesses in 2020.

Table 5-12 SDG&E Per-Customer Reference Load Forecast and COVID-19 Adjustment, by Size

Year	Large		Medium	
	Adjusted Reference Load	COVID Adjustment	Adjusted Reference Load	COVID Adjustment
2020	185.4	0.0	22.6	0.0
2021	199.1	13.7	24.9	2.3
2022	209.0	23.6	26.6	4.0

Ex-Ante Enrollment and Load Impact Summary

Table 5-13 summarizes the average event-hour load impact forecasts for non-residential CPP participants on a typical event day in 2021. The table includes impact forecasts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. Note that these estimates show impacts during the RA window, which does not coincide with SDG&E's event window (4 to 9 PM versus 2 to 6 PM, respectively). As a result, the impacts are much lower than the reported ex-post impacts since the RA window includes three post-event hours. These three post-event hours include return of load (zero impacts) or snapback behavior (negative impacts). At the program level, SDG&E contributes statistically insignificant load impacts during the RA window.

Table 5-13 SDG&E Typical Event Enrollment and Impacts by Size: 2021

Size	# of Accts	Aggregate Impact (MW)				Per-Customer Impact (kW)			
		Utility Peak		CAISO Peak		Utility Peak		CAISO Peak	
		1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Large	738	1.28	1.62	1.17	1.41	1.74	2.20	1.59	1.92
Medium	7,582	-2.18	-3.41	-1.92	-2.68	-0.29	-0.45	-0.25	-0.35
Total CPP	**8,320**	**-0.89**	**-1.79**	**-0.75**	**-1.26**	**-0.11**	**-0.21**	**-0.09**	**-0.15**

In Table 5-14 below, we also present the program level impacts by month for a SDG&E 1-in-2 weather year for 2021, 2022, and 2031. Enrollment is consistent across all months. Again, note that the load impacts are negative and insignificant because of the snapback that is likely occurring in the post-event hours coinciding with the RA window.

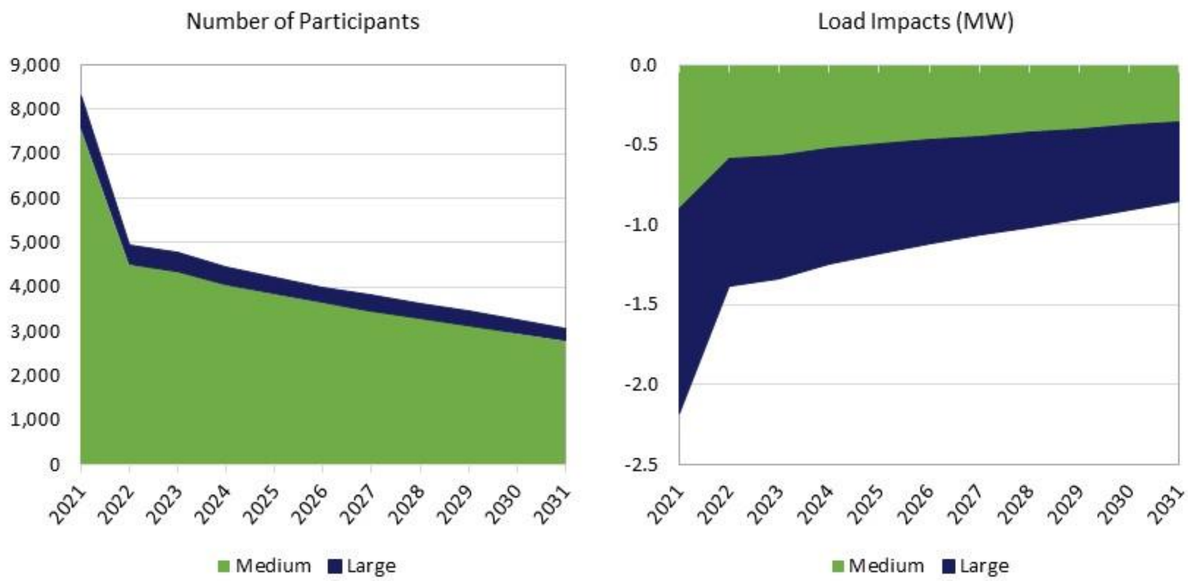
Table 5-14 SDG&E Monthly Program Level Enrollment and Impacts for Selected Years: SDG&E 1-in-2

Month	2021		2022		2031	
	Enrollment	Impact (MW)	Enrollment	Impact (MW)	Enrollment	Impact (MW)
January	8,320	-0.52	4,950	-0.42	3,063	-0.26
February	8,320	-0.55	4,950	-0.43	3,063	-0.26
March	8,320	-0.66	4,950	-0.49	3,063	-0.30
April	8,320	-0.58	4,950	-0.43	3,063	-0.27
May	8,320	-0.66	4,950	-0.47	3,063	-0.29
June	8,320	-0.75	4,950	-0.52	3,063	-0.32
July	8,320	-0.82	4,950	-0.55	3,063	-0.34
August	8,320	-0.87	4,950	-0.57	3,063	-0.35
September	8,320	-0.89	4,950	-0.57	3,063	-0.35
October	8,320	-0.86	4,950	-0.54	3,063	-0.33
November	8,320	-0.69	4,950	-0.42	3,063	-0.26
December	8,320	-0.71	4,950	-0.43	3,063	-0.26

In Figure 5-5 below, we present side-by-side comparisons of SDG&E's 11-year annual enrollment and impact forecasts for a utility 1-in-2 weather scenario on a typical event day. SDG&E anticipates a substantial decrease in participants due to the migration of bundled customers to DA/CCA service, an approximately 40% attrition in both 2021 and 2022. The forecasted impacts also show overall increases in usage in the

RA window. Note that these are statistically insignificant impacts under the SDG&E 1-in-2 weather conditions.

Figure 5-5 SDG&E Enrollment and Impact Forecast: SDG&E 1-in-2, Typical Event Day, 2021 - 2031



Comparison of Ex-Ante Impacts

In Table 5-15 below, we compare the current ex-post with the current ex-ante. This comparison highlights the effect of adjusting the impacts and reference loads to reflect the various weather scenarios required in the analysis. Here, we compare the ex-post to a 1-in-2 weather year, and we show PY2020 to be slightly hotter, on average, to a 1-in-2 weather year. This comparison shows that SDG&E's CPP participant usage has a very small negative relationship with weather, showing small increases in average reference loads and load impacts under milder temperatures.

Table 5-15 SDG&E Non-Residential CPP: Current Ex-Post (Typical Event Day) and Current Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2020), 2 to 6 PM

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Current Ex-Post	Large	1,431	297.5	5.3	207.9	3.7	1.79%	89.4
	Medium	12,244	327.0	0.2	26.7	0.0	0.06%	89.1
	All	**13,675**	**624.5**	**5.5**	**45.7**	**0.4**	**0.88%**	**89.2**
Current Ex-Ante	Large	1,427	309.1	5.5	216.6	3.8	1.77%	85.1
	Medium	12,179	338.8	0.7	27.8	0.1	0.21%	84.7
	All	**13,606**	**647.9**	**6.2**	**47.6**	**0.5**	**0.95%**	**84.9**

In Table 5-16, we compare the previous ex-ante forecast from PY2019 to the current ex-post forecast from PY2020 in both 2020 and 2022. We include both years because 2020 is still affected by COVID conditions, while by 2022, the SDG&E forecast assumes a return to a no-COVID case. A couple of key highlights include the following.

- Comparing the aggregate load impacts in MW between the two 2020 forecasts we see a decrease from 2.1 MW to -0.8 MW, although both estimates are insignificant. This is coming primarily from larger snapback impacts from the medium group.
- Comparing the reference loads between the PY2019 - 2020 and PY2020 - 2022 forecasts we see that the per-customer reference loads much higher than PY2019 (pre-COVID) levels as a result of the COVID adjustments. Despite this comparison, AEG maintains that the COVID adjustment is still appropriate given that our estimate of the COVID effect uses all data from PY2019 and PY2020 and indicates an overall decrease in usage in SDG&E CPP participants. The PY2019 ex-ante forecast also used slightly different assumptions since SDG&E did not call any events in PY2019, so the PY2019 ex-ante estimates were based on all non-event weekdays, which typically have lower usage than events and event-like days.

Table 5-16 SDG&E Non-Residential CPP: Previous and Current Ex-Ante, SDG&E 1-in-2, Typical Event Day

	Size	# Enrolled	Aggregate (MW)		Per-Customer (kW)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Prev. Ex-Ante (2020)	Large	1,289	230.9	3.3	179.1	2.5	1.42%	80.9
	Medium	12,840	285.4	-1.2	22.2	-0.1	-0.41%	80.7
	All	**14,129**	**516.3**	**2.1**	**36.5**	**0.1**	**0.41%**	**80.7**
Current Ex-Ante (2020)	Large	1,427	277.9	2.3	194.7	1.6	0.84%	80.9
	Medium	12,179	289.7	-3.2	23.8	-0.3	-1.09%	80.7
	All	**13,606**	**567.6**	**-0.8**	**41.7**	**-0.1**	**-0.15%**	**80.8**
Current Ex-Ante (2022)	Large	440	96.1	0.8	218.3	1.8	0.83%	80.9
	Medium	4,510	125.1	-1.4	27.7	-0.3	-1.10%	80.7
	All	**4,950**	**221.2**	**-0.6**	**44.7**	**-0.1**	**-0.26%**	**80.8**

6

KEY FINDINGS AND RECOMMENDATIONS

State Level Findings

In this section we present the state level findings from the Statewide PY2019 CPP, or PDP, evaluation.

Ex-Post Impacts

Table 6-1 presents the total enrollments, reference loads, load impacts, and event temperatures for the three IOU programs. In addition, the table presents the statewide total impacts for a typical event day. It is important to note that the typical event days vary by IOU based on their own weather patterns and event calling strategies, therefore this PY2020 statewide total likely overestimates what might be achievable across the state should a statewide event be needed. PG&E has the largest contribution to the overall state level total of 16.1 MW, contributing 47% of the load reduction while SCE contributes 37% and SDG&E contributes 16%.

Table 6-1 Total State Level Ex-Post Impacts by Utility: Typical Event Day

Utility	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
PG&E - PDP	101,629	807	16.1	2.0%	94.8
SCE - CPP	244,091	1,283	12.5	1.0%	84.6
SDG&E - CPP	13,675	624	5.5	0.9%	89.2
Statewide	**359,395**	**2,714**	**34.1**	**1.3%**	**87.7**

In Table 6-2 below, we also present the impacts by customer size. The large participants contribute 63% of the total impacts across the state. As noted above, the small and medium customers also showed measurable impacts this year, although they were quite small at the per-customer level, contributing 13% and 24% respectively.

Table 6-2 Total State Level Ex-Post Impacts by Customer Size: Typical Event Day

Size	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
Large (≥ 200 kW)	4,191	848	21.4	2.5%	89.9
Medium (20 kW ≤ x < 200 kW)	55,739	1,378	8.2	0.6%	88.3
Small (< 20 kW) [39]	299,465	488	4.6	0.9%	84.5
Statewide	**359,395**	**2,714**	**34.1**	**1.3%**	**85.1**

Statewide, the total MW impact increased from 19.2 MW in PY2019 to 34.1 MW in PY2020 an increase of nearly 78%. Impacts for both PG&E and SDG&E improved in PY2020 and SDG&E called events, contributing 5.5 MW (39% of the increase) to the overall statewide impact. Improvements in impacts for

[39] SDG&E's Small CPP participants are included in the SCTD evaluation and are therefore excluded from the total.

PG&E and SCE are concentrated primarily in the small and medium groups, although impacts did increase relative to PY2019 across the board. Key observations related to these improvements include the following.

- Across all three IOUs the weather was more extreme in PY2020. While the overall average temperatures were similar across the whole summer relative to PY2019, a significant heatwave hit the state in late August and early September bringing record temperatures. For weather sensitive customers the increased heat also resulted in increased impacts. Additionally, having more extreme days in our underlying data allowed for more accurate modeling of weather relationships which may also have contributed to the increase impacts.
    - PG&E's average temperature on a typical event day in PY2020 was 95° F vs. 94° F in PY2019. Additionally, the maximum average event temperature was 103 vs 96° F in PY2020 vs. PY2019.
    - SCE's average temperature on a typical event day in PY2020 was 85° F vs. 88° F in PY2019. Additionally, the maximum average event temperature was 89 vs 90° F in PY2020 vs. PY2019. SCE's temperatures were lower due to a high concentration of participants along the coast where temperatures tend to remain cooler, especially in the small and medium groups.
    - SDG&E's average event temperature on a typical event day in PY2020 was 89° F and the maximum average temperature was 99° F.
- COVID-19 conditions may also have affected how customers responded to CPP events. Given the depressed economic conditions across the country, it is possible that participants had additional incentive to save energy (and money) over the summer of 2020. Also reduced capacities at many retail and restaurant locations may have facilitated additional response.
- PG&E's PDP population experienced a significant migration from the large group to the medium group and from medium to small. We suspect this influx of larger customers in to the medium and small groups are in large part responsible for the increase in impacts.[40]
- SCE's large default population in the small and medium groups also entered their second year of participation on CPP. After twelve months, these participants lost their bill protection guarantee and were exposed to the full monetary impacts of the rate. This may have encouraged customers to increase their response to the rate.
- As noted above SDG&E called events in PY2020 vs. no events in PY2019. SDG&E customers contributed 5.5 MW or 39% of the increase to the total.

Ex-Ante Impacts

We also present the state level ex-ante impacts for a Utility 1-in-2 weather year for program years 2020 and 2030 in Table 6-3. Keep in mind that the RA window for the 2021-2031 ex-ante forecast is 4-9 PM. SCE's event window aligns with the RA window, and PG&E's event window is shifting to 5-8 PM[41] effective

[40] It is unclear whether the migration between customer size groups is a result of COVID conditions or, a result of some reclassification efforts on PG&E's side. Therefore, we maintain the existing size group distribution of participants throughout the ex-ante forecast.

[41] Pending CPUC decision for R.20-11-003, the PDP event window is expected to be modified to 4 to 9 PM at a later point.

March 2021. However, SDG&E's event windows will remain 2-6 PM, which means that SDG&E's CPP program is only available during the first two hours of the RA window while all other hours are non-event hours. This can result in significantly lower (and sometimes even negative) impacts within the RA window.

In program year 2021 the utilities forecast approximately 24.8 MW of load reduction to be available during the RA window. In 2021, SCE expects to contribute approximately 56% of the overall impacts, PG&E contributing 47%, and SDG&E contributing -4%, increasing loads on average during the RA window are due to snapback after the event.

By 2031 the IOUs forecast a total of 24.3 MW of demand response on a typical event day. SCE predicts an increase in enrollments and impacts to 17.1 MW, but PG&E predicts a steep decline in enrollments and impacts to 7.6 MW.[42] SDG&E also predicts an overall decrease in enrollments and an associated reduction in load increases during the RA window to -0.4 MW.

Table 6-3 Total State Level Ex-Ante Impacts by Utility: Utility 1-in-2, Typical Event Day

Utility	PY 2021 Enrollment	PY 2021 Load Impact (MW)	PY 2031 Enrollment	PY 2031 Load Impact (MW)
PG&E- PDP	126,582	11.8	37,295	7.6
SCE - CPP	255,557	14.0	296,059	17.1
SDG&E - CPP	8,320	-0.9	3,063	-0.4
Statewide	**390,459**	**24.8**	**336,417**	**24.3**

In Table 6-4 we also present the ex-ante impacts for 2021 and 2031 by customer size. In the ex-ante scenario, the large customers still contribute most of the impacts. In 2031, with changes in impacts due to changing enrollments across the three size groups and utilities.

Table 6-4 Total State Level Ex-Ante Impacts by Customer Size: Utility 1-in-2, Typical Event Day

Size	PY 2021 Enrollment	PY 2021 Load Impact (MW)	PY 2031 Enrollment	PY 2031 Load Impact (MW)
Large (≥ 200 kW)	4,749	18.6	3,117	16.8
Medium (20 kW ≤ x < 200 kW)	55,495	3.9	41,591	5.5
Small (< 20 kW) [43]	330,216	2.3	291,709	2.0
Statewide	**390,460**	**24.8**	**336,417**	**24.3**

Event Communication

It is also important to keep in mind that not all the customers that were enrolled in CPP, or PDP, received communication regarding events. As customers were defaulted onto the rates, each utility established mechanisms to reach out to customers to obtain contact information that could be used to provide day ahead event notification, however, in many cases customers did not respond to the utility outreach and therefore were unaware of the events throughout the summer. Table 6-5 shows the percentage of participants that were notified by utility and size group on a typical event day.

[42] PG&E's enrollment forecast incorporates the attrition trend from PY2019 to PY2020 and extends this trend into all future years. Without backfill from additional defaults after March of 2021, attrition continues to erode the program participation as shown.

[43] SDG&E's Small CPP participants are included in the SCTD evaluation and are therefore excluded from the total.

Interestingly, we saw very little evidence among the participating customers within the IOU programs that indicates notifications are having a significant effect on impacts. In fact, in many cases we see the groups of customers that have not elected email or text notification with larger per-customer impacts than those that have elected to receive notification. While this is counterintuitive, we also know that the IOUs communicate[44] about events to customers using multiple channels including via the website.

Table 6-5 Percent of Service Accounts Notified, by Utility and Size Group, Typical Event Day

Size Group	PG&E % Notified	SCE % Notified	SDG&E % Notified
Large (≥ 200 kW)	87%	81%	63%
Medium (20 kW ≤ x < 200 kW)	87%	86%	48%
Small (< 20 kW)	84%	86%	-
Total	**84%**	**86%**	**50%**

Key Findings by Utility

The key results for each utility on a typical event day are summarized in Table 6-6 (PG&E), Table 6-7 (SCE), and Table 6-8 (SDG&E).

Table 6-6 Key Results for PG&E's Peak Day Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
PG&E	Large	865	220	7.7	3.5%	96.4
	Medium	13,914	383	4.6	1.2%	95.9
	Small	86,850	204	3.8	1.8%	92.5
ALL PG&E		**101,629**	**807**	**16.1**	**2.0%**	**94.8**

The Large customers participating in PG&E's PDP program in 2020 demonstrate large and consistent load impact reduction as a group, similar to past years. In addition, the medium and small customer groups show small but consistent load reductions which are an improvement over previous years likely attributable to extreme weather and possibly increased sensitivity to price resulting from COVID.

[44] SCE does this via the DR mobile app, alerts on www.sce.com, and Facebook postings.

Table 6-7 Key Results for SCE's Critical Peak Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Avg. Event Temp.
SCE	Large	1,895	330	8.3	2.5%	87.2
	Medium	29,581	669	3.4	0.5%	84.4
	Small	212,615	284	0.8	0.3%	81.2
ALL SCE		**244,091**	**1,283**	**12.5**	**1.0%**	**84.6**

The large customer group in SCE's CPP Program also demonstrates large and consistent load impact reduction. In addition, the small and medium customers defaulted by SCE show improvements in their response this year, although the per-customer impacts are still very small.

Table 6-8 Key Results for SDG&E's Critical Peak Pricing Program for PY2020

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Event Temp
SDG&E	Large	1,431	298	5.3	1.8%	89.4
	Medium	12,244	327	0.2	0.1%	89.1
ALL SDG&E		**13,675**	**624**	**5.5**	**0.9%**	**89.2**

SDG&E's customers show similar trends to the other two IOUs, with the largest impacts coming from the large customer group, and small, but positive impacts coming from the medium group.

Recommendations

AEG has developed three recommendations for future research and evaluation related to the non-residential CPP programs.

- Investigate the experiences of small and medium participants. While PY2020 saw improvements in the impacts among small and medium customers, we do not fully understand why the impacts improved. Several factors including, extreme weather, increased price sensitivity during COVID, and loss of bill protection are all possibilities. Through future or ongoing process evaluations, ensure that special care is taken to better understand the experiences of small and medium customers on the CPP rates and the various factors that contribute to their response. Participant surveys and focus groups can be used to understand aspects of participation including, effects of extreme weather, effects of COVID, awareness and understanding of the rate, awareness of participation, awareness of events, ability to respond to events, and actions taken during events. Conducting research while maintaining statistically significant samples by key industry group and size may provide invaluable insights for both program staff and future impact evaluations.
- Investigate the effect of notifications on customer impacts. Again, through the use of participant surveys and/or focus groups, conduct research to better understand participant choices regarding notification, their awareness of notifications, and how they respond to notifications on event days. It would also be of interest to know how those that elected not to receive notifications learn about events.

- Consider opportunities to improve robustness of within-subjects designs. For most of the subgroups, we elected not to develop a matched control group for this evaluation because of the small ratios of participants to non-participants and the opt-out nature of the CPP, or PDP, rates which would likely lead to poor matches and introduce self-selection bias. Unfortunately, the within-subjects design may also have led to the introduction of bias, particularly among those groups with very small impacts due to a lack of truly comparable event like days. Since all utilities expect their participant population to grow (and the non-participant pools to continue to shrink) we recommend considering the following opportunities to mitigate this bias in the future. We propose two options for consideration:
    - Intentionally call test events on cooler days and, unless absolutely necessary, try not to call events on all the hottest days of the season. This will provide the models with better information as to how participants would behave during events on a wider range of temperatures and improve their performance.
    - Consider developing a randomized EM&V group that could be used as a control during events. These customers might not be called to respond on all event days, or, might be called to respond on alternate days. This would significantly improve the ability of the evaluation to detect the true impact of the CPP program.

A

TABLE GENERATORS

PG&E PDP Ex-Post Table Generator

PG&E PDP Ex-Ante Table Generator

SCE CPP Ex-Post Table Generator

SCE CPP Ex-Ante Table Generator

SDG&E CPP Ex-Post Table Generator

SDG&E CPP Ex-Ante Table Generator

B

MODEL VALIDITY

We selected and validated subgroup level regression models during our optimization process; participants are grouped based on size and industry type. For a small subset of extremely large (x-large) participants, we selected and validated customer-specific regression models with our optimization process used primarily in our Statewide Capacity Bidding Program LI evaluations. Both subgroup and customer-specific models are designed to be able to:

- Accurately predict the actual participant load on event days, and
- Accurately predict the reference load, or what customers would have used on event days, in absence of an event.

To meet these two specific goals, our optimization process included an analysis of both the in-sample and out-of-sample mean absolute percent error (MAPE) and mean percent error (MPE) for each of the candidate regression models for each group. We used the out-of-sample tests to show how well each of the candidate models could predict a customer's load on non-event days that were as similar as possible to actual event days; this test gave us an estimate of how well each model could predict the reference load. We used the in-sample tests to show how well each model performed on the actual event days; therefore, it helped us understand how well the model was able to match the actual load.

As described in Section 3, our optimization procedure has four key steps: (1) assessing weather sensitivity; (2) in-sample and out-of-sample testing; (3) assessing model validity; and, (4) model fine-tuning. This section presents metrics related to steps 2 and 3, specifically:

- Selection of event-like days used in out-of-sample testing.
- Metrics from in-sample and out-of-sample tests from the final models of the ex-post analysis: MAPE, MPE, and comparison load graphs.

Selecting Event-Like Days

To select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. To determine how close event day temperature is to a potential event-like day, we calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance; in this program year, we included three weather variables in the Euclidean distance metrics calculation to select similar non-event days: (1) daily maximum temperature; (2) daily minimum temperatures; and (3) average daily temperature. The Euclidean distance metric used can be calculated by Equation B1 below.

$$ED = \sqrt{\begin{matrix}(MaxTemp_{event} - MaxTemp_{non-event})^2 + (MinTemp_{event} - MinTemp_{non-event})^2 \\ +(MeanTemp_{event} - MeanTemp_{non-event})^2\end{matrix}} \quad \text{(B1)}$$

In Figure B-1 to Figure B-3, we show comparisons of the distributions of average daily temperature of event days and event-like days. We show a single utility level comparison because these dates were chosen at the utility level, i.e. all subgroups have the same set of event and event-like dates.

Figure B-1 PG&E Average Daily Temperatures of Event Days v. Event-Like Days

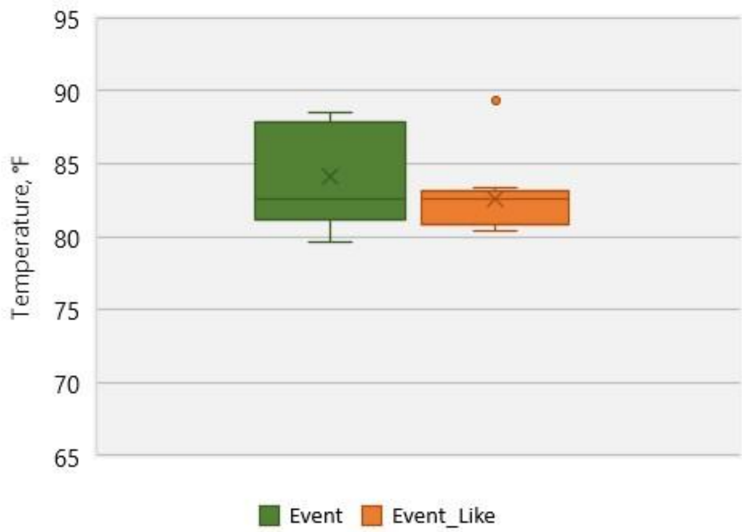


Figure B-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

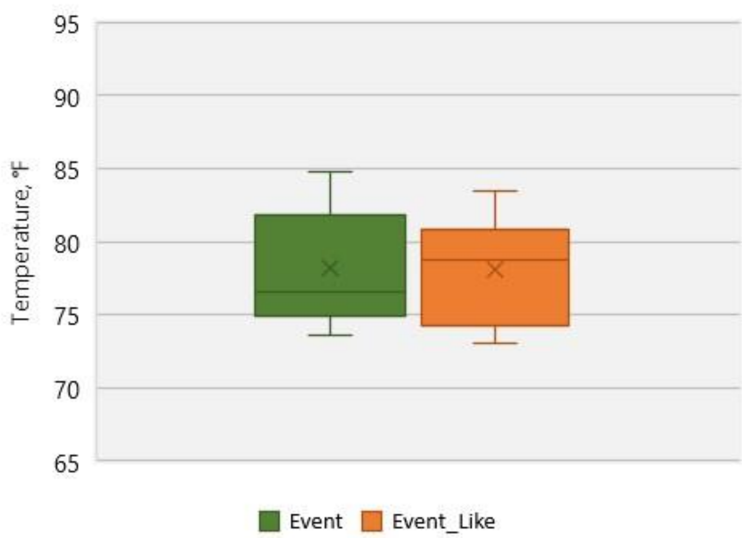
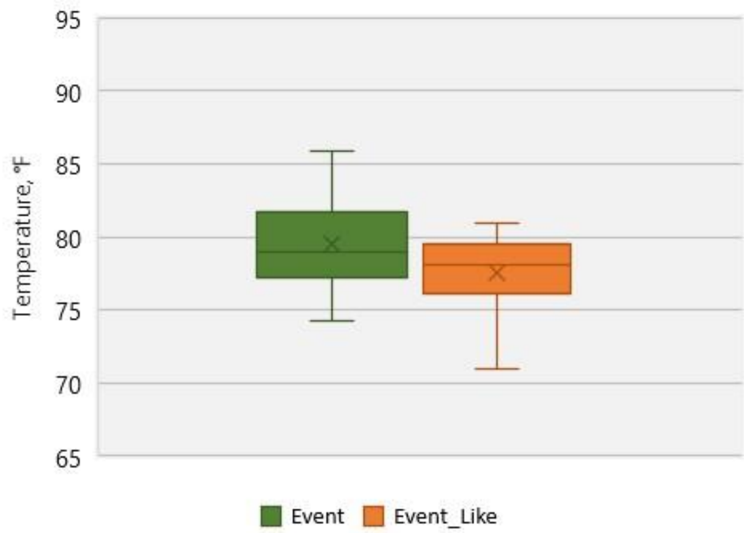


Figure B-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

Next, we estimated the MAPE and MPE, for the entire day, for each subgroup/customer, and for each candidate model, both for the in-sample and the out-of-sample scenarios:

- To perform the in-sample test, we fitted each candidate model to the entire data set. The results of these fitted models are used to predict the usage on event days. Then we assessed the accuracy and bias of the predictions by calculating the in-sample MAPE and in-sample MPE, respectively.
- To perform the out-of-sample test, we remove the out-of-sample event-like days from the analysis dataset and the candidate models are fitted to the remaining data. Then we assessed the accuracy and bias of the predictions by calculating the out-of-sample MAPE and out-of-sample MPE, respectively.

These two tests resulted in several in-sample and out-of-sample metrics. Recall that the goal of the tests is to find the best model for each subgroup in terms of its ability to predict the reference load and the actual load for each subgroup. Therefore, for each subgroup, we combined the two tests into a single metric, giving each candidate model a single metric. The metric is defined in as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + \big(0.1 * abs(MPE_{in})\big) + \big(0.1 * abs(MPE_{out})\big)$$

Where,

$$MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right|, \qquad MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h}$$

Once we have a single metric for each subgroup and candidate model combination, we selected the best model for each subgroup by choosing the model specification with the smallest overall metric. The results of the optimization process are shown in the following tables and figures.

Table B-1 presents the weighted average MAPE and MPE for the final set of models for each utility, by size. Except for PG&E's small group, all three IOUs and size groups have MAPE and MPE estimates below 2.1%.

PG&E's small group has approximately 4.3% MAPE and MPE, which are still relatively low. We see very see very small MPE values, which indicate relatively low level of bias. Most out-of-sample MPE values are negative and most in-sample MPE values are positive, which indicates that withholding event-like days cause predicted reference loads that are higher than actual values.

Table B-1 Weighted Average MAPE and MPE by Utility and Size

	Size	Out-of-Sample		In-Sample	
		MAPE	**MPE**	**MAPE**	**MPE**
PG&E	Large	1.74%	1.37%	2.03%	1.79%
	Medium	1.19%	-1.04%	0.13%	-0.02%
	Small	0.95%	0.48%	4.35%	4.30%
SCE	Large	1.72%	1.69%	0.46%	0.31%
	Medium	0.74%	0.74%	0.03%	0.03%
	Small	0.53%	-0.41%	1.31%	1.23%
SDG&E	Large	0.61%	-0.42%	0.12%	0.11%
	Medium	1.01%	-0.60%	0.37%	0.37%

Figure B-4 to Figure B-6 present the average event-like day predicted loads (dotted lines) and actual loads (solid lines) from the in-sample and out-of-sample tests by utility and size group. In each case, the predicted load is very close to the actual load. This tells us that on average, the customer-specific regression models do a very good job estimating what customer loads would be like on event-like days, and therefore are able to produce very accurate reference loads.

Figure B-4 PG&E Actual and Predicted Loads

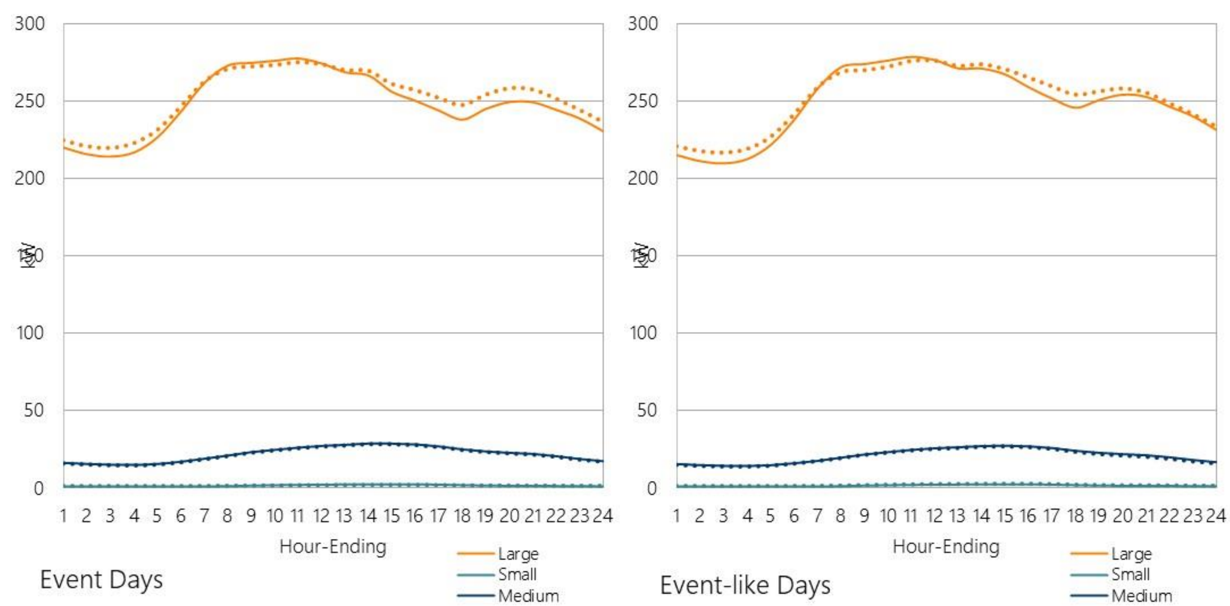


Figure B-5 SCE Actual and Predicted Loads

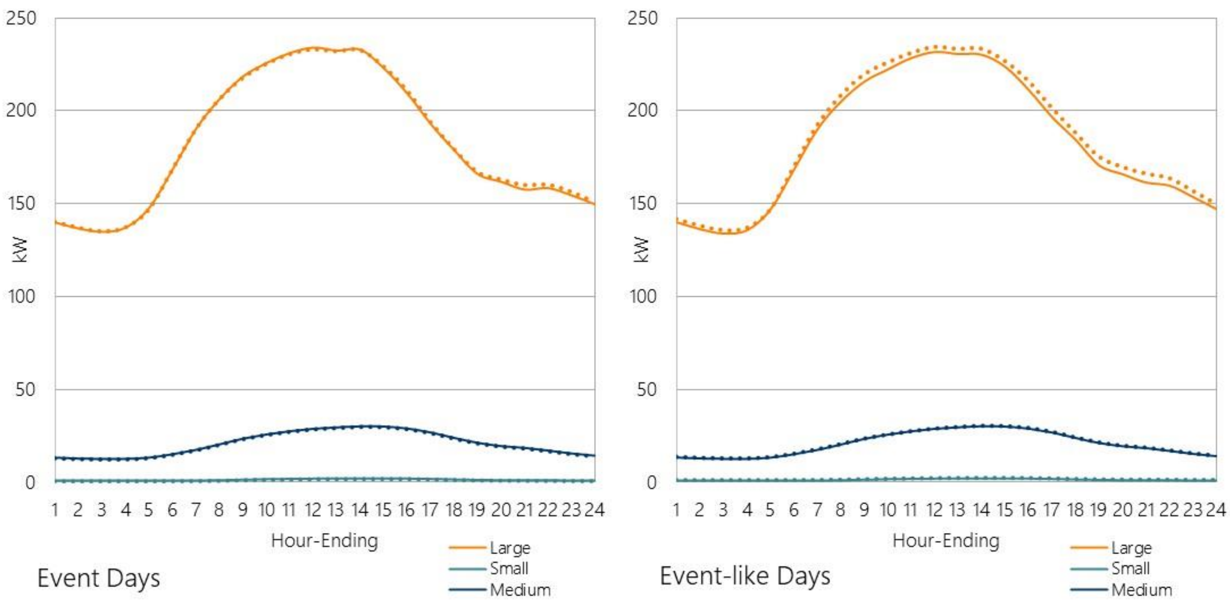
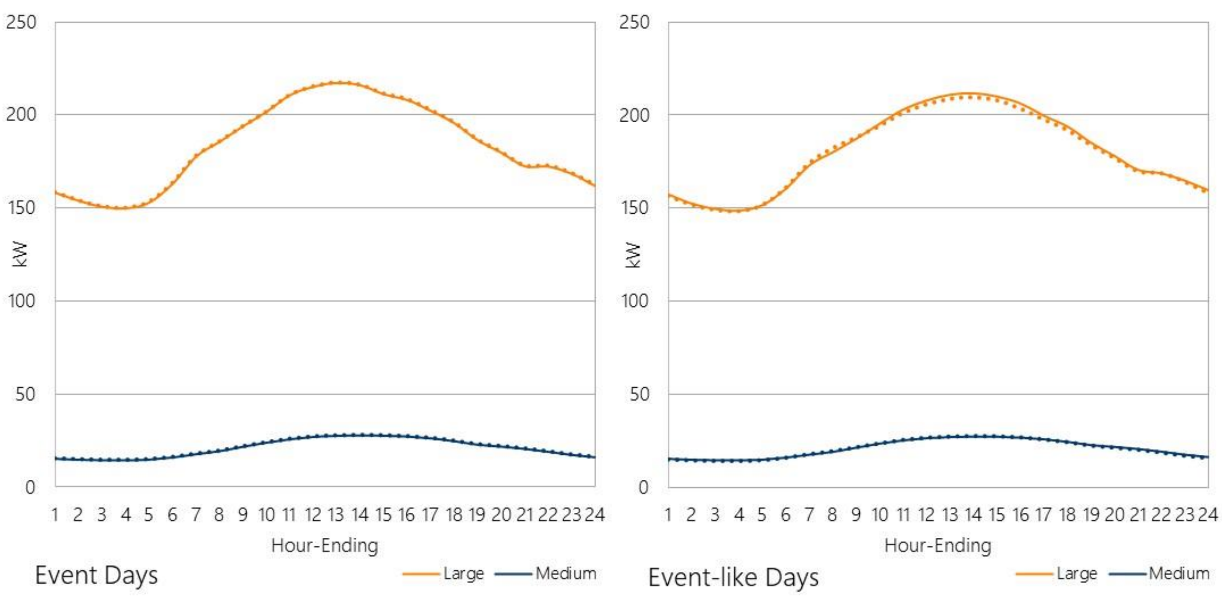


Figure B-6 SDG&E Actual and Predicted Loads



Additional Checks

Visual inspection can be a simple but highly effective tool. During the inspection, we looked for specific aspects of the predicted and reference load shapes to tell us how well the models performed. For example,

- We checked to make sure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event.

Large differences can indicate that there is a problem with the reference load either over- or under-estimating usage in absence of the event.

- We closely examined the reference load for odd increases or decreases in load that could indicate an effect that is not properly being captured in the models. If we found such an increase or decrease, we investigated the cause and attempted to control for the effect in the models.
- We also looked for bias, both visually and mathematically. Bias is the consistent over- or under-prediction of the actual load. We may see bias that is temperature-related, under-predicting on hot days, and over-predicting on cool days. We have also seen bias that is time-based, over-predicting in the beginning of the year, and under-predicting at the end of the year. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

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